The original documents are located in Box 46, folder "1975/06/07-08 - Camp David Energy Meeting (2)" of the James M. Cannon Files at the Gerald R. Ford Presidential Library.

ENERGY RESOURCES COUNCIL

EXECUTIVE COMMITTEE

ENERGY MEETING

CAMP DAVID
JUNE 7 and 8, 1975

FEDERAL ENERGY ADMINISTRATION
WASHINGTON, D.C. 20461

May 30, 1975

OFFICE OF THE ADMINISTRATOR

MEMORANDUM FOR	BILL ANDERS JIM CANNON TOM ENDERS ALAN GREENSPAN STAN HATHAWAY JIM LYNN	ROGERS MORTON GERRY PARSKY JOHN QUARLES BOB SEAMANS BILL SEIDMAN
FROM :	FRANK ZARB Z	
SUBJECT:	CAMP DAVID ENERGY MEETING	

Enclosed are background materials for the Camp David meeting on June 7 and 8. ERDA papers to support the Saturday research and development discussion will be distributed later.

These papers on the current policy matters to be discussed were prepared as "think-pieces" to promote an open and unstructured exchange of ideas. Since we are all familiar with these issues and have discussed them before, it was not our intention to develop lengthy "options papers," but rather to develop documents which would present balanced statements of the issues, reflect the range of views and perspectives on these matters within the Administration and point out key issues which must be addressed. Of course, staff contact has been made where necessary to insure that the papers are as fully representative as possible.

As noted earlier, we expect the meeting to provide a forum in which we can spend time discussing these matters at length and without interruption. And while few immediate policy decisions are expected to result from the meeting, the dialogue on these issues within the executive branch will certainly be enhanced, and plans on how next to proceed may be developed.

As you will note by the enclosed agenda, which is unchanged from that originally circulated, the plan remains to have the agency closest to each issue lead off the discussion.

Enclosures

ENERGY MEETING - CAMP DAVID

JUNE 7 AND 8, 1975

BACKGROUND MATERIAL

To Be Distributed Later

ERDA Research and Development Background Material

Biweekly Progress Report

PRESIDENT's ENERGY PROGRAM

May 27, 1975

Energy Resources Council

FEDERAL ENERGY ADMINISTRATION
WASHINGTON, D.C. 20461

May 27, 1975

OFFICE OF THE ADMINISTRATOR

MEMORANDUM FOR THE PRESIDENT

FROM: Frank G. Zarb FGZ

THROUGH: Rogers C. B. Morton

SUBJECT: Biweekly Status Report

Legislative Status

The House voted to postpone floor consideration of the vetoed Surface Mining legislation until June 10 by a narrow margin of 208-195.

The House Ways and Means Committee completed action on its energy tax bill. A Rule is expected to be granted immediately after the Memorial Day Recess.

The Energy and Power Subcommittee of the House Interstate and Foreign Commerce Committee completed work on its omnibus energy plan and has referred the legislation to the full committee. The legislation provides for decontrol of old oil at a rate of 1 percent per month retroactive to May 1972.

Status of One Million Barrel Savings Program

Details on imports, apparent demand, prices and crude oil production are presented in Tab C. The following are significant trends:

- Domestic crude oil production for the four weeks ending May 9 increased by 2 percent over the four week period ending April 11, to a level of 8.4 million barrels per day. However, production to date this year is 5.8 percent below 1974.

- Demand for motor gasoline was 0.25 million barrels per day above the President's target, but only slightly above the forecast without the program.

Major International Developments

Saudi Arabia's Sheikh Yamani has said that OPEC will consider linking the price of oil to some yardstick other than the U.S. dollar.

The Shah of Iran anticipates that OPEC will end the nine-month price freeze and increase prices at its September meeting.

A

TAB A

Action on Energy Legislation

Action on Energy Legislation

Congressional Action

- On May 21, the House voted to postpone floor consideration of HR 25, the Surface Mining Control and Reclamation Act, by a narrow margin of 208-195. The leadership acknowledged that they did not have the votes to override the President's veto. Floor consideration of the bill has been scheduled for June 10.

- The Energy and Power Subcommittee of the House Interstate and Foreign Commerce Committee reported its energy legislation, HR 7014, to the full Committee. Title III of the legislation provides for decontrol of old oil at a rate of 1 percent per month retroactive to May 1972.

- On May 14, the House Interstate and Foreign Commerce Committee passed H Res 439, which disapproves the President's proposal to remove existing price controls on old oil. The Resolution has been tabled by the Committee until the President's decontrol plan is submitted to Congress.

- The House Ways and Means Committee voted out its energy tax bill on May 12 by a margin of 19-16. The House Rules Committee postponed granting a rule on this bill, HR 6860, until June 2.

- The Senate Interior and Insular Affairs Committee approved the nomination of Stanley K. Hathaway to be Secretary of the Interior.

- The House Interior and Insular Affairs Committee continued its hearings on coal slurry pipeline legislation during the weeks of May 12 and May 19. The Committee also continued markup sessions on HR 3510, Land Use and Resources Conservation Act of 1975.

- The Subcommittee on Environment and Land Resources of the Senate Interior and Insular Affairs Committee held a hearing on May 15 on S 507, the proposed National Resource Lands Management Act, and S 1292, legislation to provide for the management of the National Resource Lands.

- Legislation was introduced in the Senate, S 1754, which would establish a National Oil Pollution Compensation Liability Administration and a National Oil Pollution Compensation Fund supported by oil company fees.

PROGRESS OF ENERGY LEGISLATION: May 12 - May 23

ADMINISTRATION BILL OR COMPONENT	ADMINISTRATION ACTION	CONGRESSIONAL ACTION HOUSE	CONGRESSIONAL ACTION SENATE	SIGNIFICANT CONGRESSIONAL ACTION
A. OMNIBUS ENERGY BILL (HR 2633, HR 2650, S 594) Title I - Naval Petroleum Reserve Development/ Military Strategic Reserve Title II - National Strategic Petroleum Reserve		On March 18, the Interior and Insular Affairs Committee reported HR 49, a bill to transfer the management of the Naval Petroleum Reserve to the Department of the Interior. Armed Services Committee reported HR 5919, which continues NPR management under the Navy, on April 18. Energy and Power Subcommittee of the Interstate and Foreign Commerce Committee reported its omnibus energy plan, HR 7014, on May 13. The bill is pending full committee action. (Title II, Part E, Strategic Reserves)	Armed Services Committee is considering introducing a clean bill this summer. Joint hearings with the Interior and Insular Affairs Committee were held in March. (Title I) Interior and Insular Affairs Committee is expected to begin mark up sessions on a revised version of S 677, Senator Jackson's reserves bill, rather than on the President's, after the recess. (Title II)	On April 22, House Rules Committee granted an open rule with two hours of debate (to be divided between the Interior and Insular Affairs Committee and the Armed Services Committee) making HR 49 in order as an original bill with the text of HR 5919 in order as a substitute. Floor action is pending.
Title III - Natural Gas Amendment		House Interstate and Foreign Commerce and Ways and Means Committees have postponed action on natural gas until work on their respective omnibus energy bills is completed.	Commerce Committee ordered the bill S 692 reported with amendments on May 6. Floor action is expected in June.	
Title IV - Energy Supply and Environmental Coordination Act of 1974 Extension	Administration witnesses will appear before the Senate Public Works Committee hearings scheduled for the beginning of June. Russell Train, Administrator of EPA, testified before the Subcommittee on Environmental Pollution of the Senate Public Works Committee on May 21.	Energy and Power Subcommittee of Interstate and Foreign Commerce Committee reported its omnibus energy plan, HR 7014, on May 13. The bill is pending full committee action. (Title VI included coal conversion.)	The Public Works Committee and S Res 45 members have scheduled hearings for the beginning of June on coal conversion and ESECA Act. Administration witnesses will testify. On May 21, the Subcommittee on Environmental Pollution of the Public Works Committee concluded its final two weeks of hearings on Clean Air Act Amendments. Mark up sessions are expected to begin in mid-June.	

PROGRESS OF ENERGY LEGISLATION: May 12 - May 23

ADMINISTRATION BILL OR COMPONENT	ADMINISTRATION ACTION	CONGRESSIONAL ACTION: HOUSE	CONGRESSIONAL ACTION: SENATE	SIGNIFICANT CONGRESSIONAL ACTION
Title V - Clean Air Amendments Title VI - Significant Deterioration	Administration witnesses will appear before the Senate Interior and Insular Affairs Committee in hearings scheduled for the beginning of June. Russell Train, Administrator of EPA, testified before the subcommittee on Environmental Pollution of the Senate Public Works Committee on May 21.	Energy and Power Subcommittee of Interstate and Foreign Commerce Committee reported its omnibus energy plan, HR 7014, on May 13. The bill is pending full committee action. (Title V, Part A, Automobile Fuel Economy and Efficiency Standards, and Title VI, Coal Conversion) Health and Environment Subcommittee of Interstate and Foreign Commerce Committee continued mark up sessions on Clean Air Act Amendments during the week of May 12.	The Public Works Committee and S Res 45 members have scheduled hearings for the beginning of June on coal conversion and ESECA Act. Administration witnesses will testify. On May 21, the Subcommittee on Environmental Pollution of the Public Works Committee concluded its final two weeks of hearings on Clean Air Act Amendments. Mark up sessions are expected to begin in mid-June.	
Title VII - Utilities Act of 1975	Administration witnesses are expected to appear before the Energy and Power Subcommittee of House Interstate and Foreign Commerce Committee at a future date not yet scheduled by the Subcommittee.	Energy and Power Subcommittee of Interstate and Foreign Commerce Committee is expected to hold hearings after completion of its "Energy Conservation and Oil Policy Act of 1975," HR 7014. Administration witnesses are expected to testify at that time.	The Government Operations Committee is planning to draft legislation to preempt Title VII.	

PROGRESS OF ENERGY LEGISLATION: May 12 - May 23

ADMINISTRATION BILL OR COMPONENT	ADMINISTRATION ACTION	CONGRESSIONAL ACTION HOUSE	CONGRESSIONAL ACTION SENATE	SIGNIFICANT CONGRESSIONAL ACTION
Title VIII - Energy Facilities Planning and Development (S 619)	Administration witnesses are expected to appear before the Energy and Power Subcommittee of House Interstate and Foreign Commerce Committee at a future date not yet scheduled by the Subcommittee.	Energy and Power Subcommittee of Interstate and Foreign Commerce Committee is expected to hold hearings after completion of its "Energy Conservation and Oil Policy Act of 1975." Administration witnesses are expected to testify at that time.	Environment and Land Resources Subcommittee of the Interior and Insular Affairs Committee completed hearings on Title III and S 984, "Land Resources Planning Assistance Act", on May 2. The Committee is waiting for action in the House before beginning mark up sessions.	
Title IX - Energy Development Security		Energy and Power Subcommittee of the Interstate and Foreign Commerce Committee reported its omnibus energy plan, HR 7014, on May 13. The bill is pending full committee action. (Title II, Part A, Section 211, International Voluntary Agreements of HR 7014.)	On May 1, the Senate passed S 621 which prohibits the use of certain authorities by the President for the purposes of establishing a floor price for imported petroleum.	
Title X - Building Energy Conservation Standards Title XI - Winterization Assistance		House passed HR 4485, the Emergency Middle-Income Housing Act of 1975, on March 21. Housing and Community Development Subcommittee of the Banking, Currency and Housing Committee is continuing mark up sessions on its winterization assistance legislation, HR 3573. Certain provisions dealing with Title XI are included in HR 5005, the Ways and Means Committee omnibus energy bill.	The bill, HR 4485, passed by the Senate amended on April 24. The President's Title X was incorporated in the Senate provision. (S 1483)	Conference on HR 4485 was completed on May 12. Conferees deleted the President's Title X which had been incorporated in the Senate version.

PROGRESS OF ENERGY LEGISLATION: May 12 - May 23

ADMINISTRATION BILL OR COMPONENT	ADMINISTRATION ACTION	CONGRESSIONAL ACTION		SIGNIFICANT CONGRESSIONAL ACTION
		HOUSE	SENATE	
Title XII - National Appliance and Motor Vehicle Energy Labeling		Energy and Power Subcommittee of the Interstate and Foreign Commerce Committee reported its omnibus energy plan, HR 7014, on May 13. The bill is pending before the full committee. (Title V, Part A, Energy Efficiency Standards for Automobiles; Title V, Part B, Other Consumer Products Standards, of HR 7014.)	Compromises will be made between Title XII and Senator Tunney's bill, S 349. No action is expected by the Commerce Committee in the next several months.	
Title XIII - Standby Authorities Act (S 620)		Energy and Power Subcommittee of the Interstate and Foreign Commerce Committee reported its omnibus energy plan, HR 7014, on May 13. The bill is pending before the full committee. (Title II, Standby Authorities, of HR 7014.)	Interior and Insular Affairs reported S 622 on March 5. The report number is 94-26.	On April 10, the Senate passed S 622 by a margin of 60-25.
B. <u>OTHER BILLS-SUPPLY</u> Surface Mining Legislation (HR 3110, S652)		By a margin of 293-115, the House passed the Conference Report on HR 25 on May 7.	By voice vote, the Senate passed the Conference Report on HR 25 on May 5.	On May 20, the President vetoed the Conference Report on HR 25. By a narrow margin of 208-195, the House adopted Mr. Udall's motion to postpone floor consideration until June 10.
Nuclear Licensing and Siting Bill		On May 5, OMB approved the NRC draft bill after receiving comments from appropriate agencies.		

ADMINISTRATION BILL OR COMPONENT	ADMINISTRATION ACTION	CONGRESSIONAL ACTION HOUSE	CONGRESSIONAL ACTION SENATE	SIGNIFICANT CONGRESSIONAL ACTION
Nuclear Insurance Bill		Comments to OMB from appropriate agencies on the draft bill are expected to be completed in the near future.		
C. TAX PROPOSALS Windfall Profits Tax Petroleum Excise Tax and Import Fee Natural Gas Excise Tax Uniform Investment Tax Credit Higher Investment Tax Credit Preferred Stock Dividend Deductions Residential Conservation Tax Credit		The following are the components of HR 6860: Title I: Quotas, Allocations and Strategic Reserves. Title II: Gasoline Conservation Program. Title III: Other Transportation Energy Programs. Title IV: Energy Conservation and Conversion Trust Fund. Title V: Deregulation of Oil and Natural Gas; Windfall Profits. Title VI: Revisions of Capital Incentives for Extraction in Producing Industries. Title VII: Industrial Conversions. The Committee completed work on this bill on May 12.		On May 20, the House Rules Committee held a full day debate on the Ways and Means' Energy Conservation and Conversion Act of 1975 (HR 6860); the Committee agreed to resume consideration on June 2.

B

TAB B

Progress Report on Administrative Actions Within the President's Energy Program

(

Progress Report on Administrative Actions Within the President's Energy Program

Administrative Activity	Lead Agency	Status	Next Steps
Near Term Program			
1. Crude Oil Decontrol	FEA	S 621 was passed by the Senate on May 1 and sent to the House. Action on this bill and HR 4035 has been postponed until after the Congressional recess.	Action will depend upon House action and reaching a compromise on the overall energy program.
2. Energy Conservation	FEA	Draft guidelines for using energy conservation "mark" have been completed. Legislation has been drafted regarding the use and protection of the "mark".	Will submit legislation to OMB for approval before submitting to Congress.
3. Coal Conversion	FEA	Public hearings being held in six regions during May and early June. First hearing held in Kansas City May 20.	Letters of intent are being issued in five regions between mid-May and early June. Final prohibition orders to be issued prior to June 1.
4. Import Fee Implementation	FEA	On May 1 the President announced his intention to delay further increases of the import fees for up to 30 days.	Further action will depend on evolving a compromise on the overall energy program.

Administrative Activity	Lead Agency	Status	Next Steps
Mid Term Program			
1. OCS Leasing	DOI	Final programmatic EIS on accelerated leasing program to be published by May 31. Central Gulf sale of 1.8 million acres to be held May 28. Sale of second half of Central Gulf tract to be held in early June.	Issuance of final rulemaking on ban on joint bidding by major oil companies targeted for June 1. Final EIS and final rulemaking on accelerated leasing program scheduled to be effect by late August.
2. Auto Emission Standards	EPA	Summary issue paper has been prepared. Senate Public Works Subcommittee on Air and Water Pollution currently holding hearings. House Subcommittee on Public Health and Environment have tentatively set standards more stringent than those recommended by EPA.	Issue paper under consideration by ERC.
3. Auto-Efficiency Agreements	DOT	The four major automobile manufacturers have agreed in principle to the monitoring process. House and Senate Commerce Committees have marked up legislation setting mandatory auto-efficiency standards.	Quarterly production reports and semiannual sales reports to be submitted by the manufacturers.

Administrative Activity	Lead Agency	Status	Next Steps
Mid Term Program (Cont'd)			
4. Appliance Standards	NBS	Draft legislation has been prepared by Commerce, FEA, and FTC for submission to House Subcommittee on Energy and Power.	Await Congressional action.
5. Emergency Storage	FEA	Draft RFP's have been approved by FEA's Contract Review Board for solicitation by June 30.	First phase analysis to be completed by Task Force by June 3

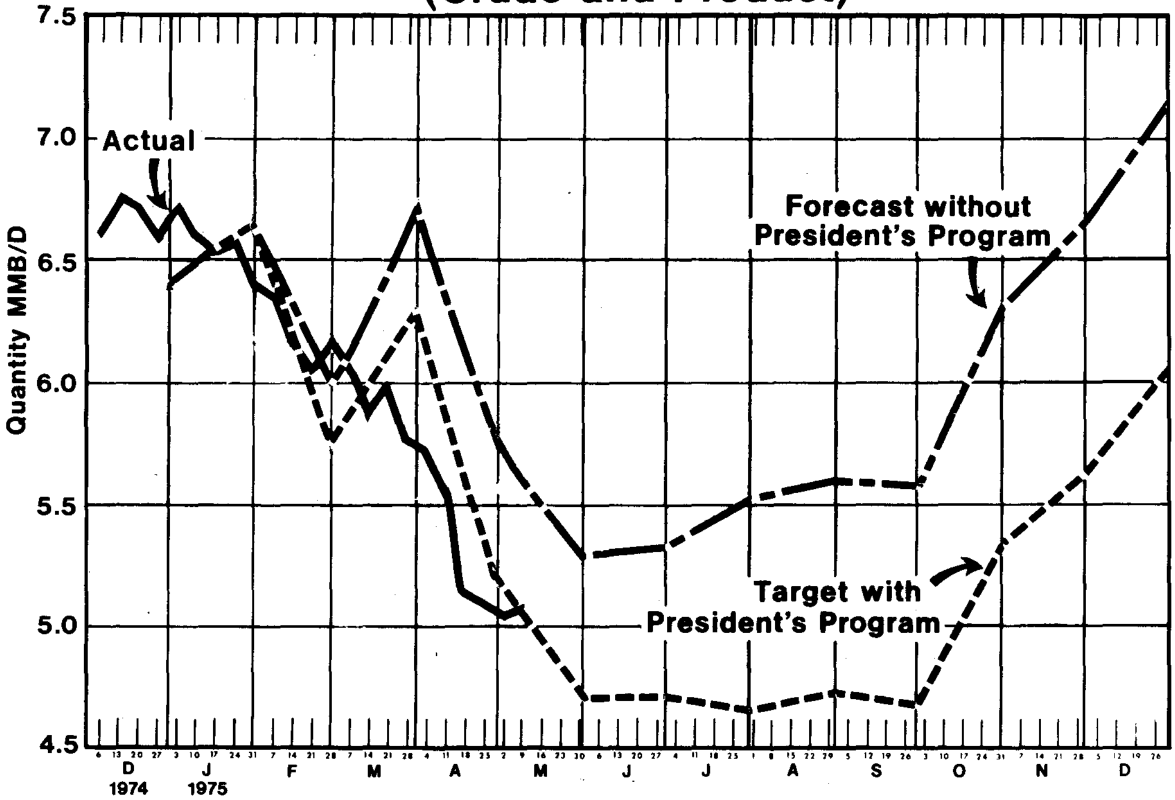
C

TAB C

Progress In Meeting Goal of One Million Barrels Savings in 1975

Table 1

Total U.S. Petroleum Imports (Crude and Product)



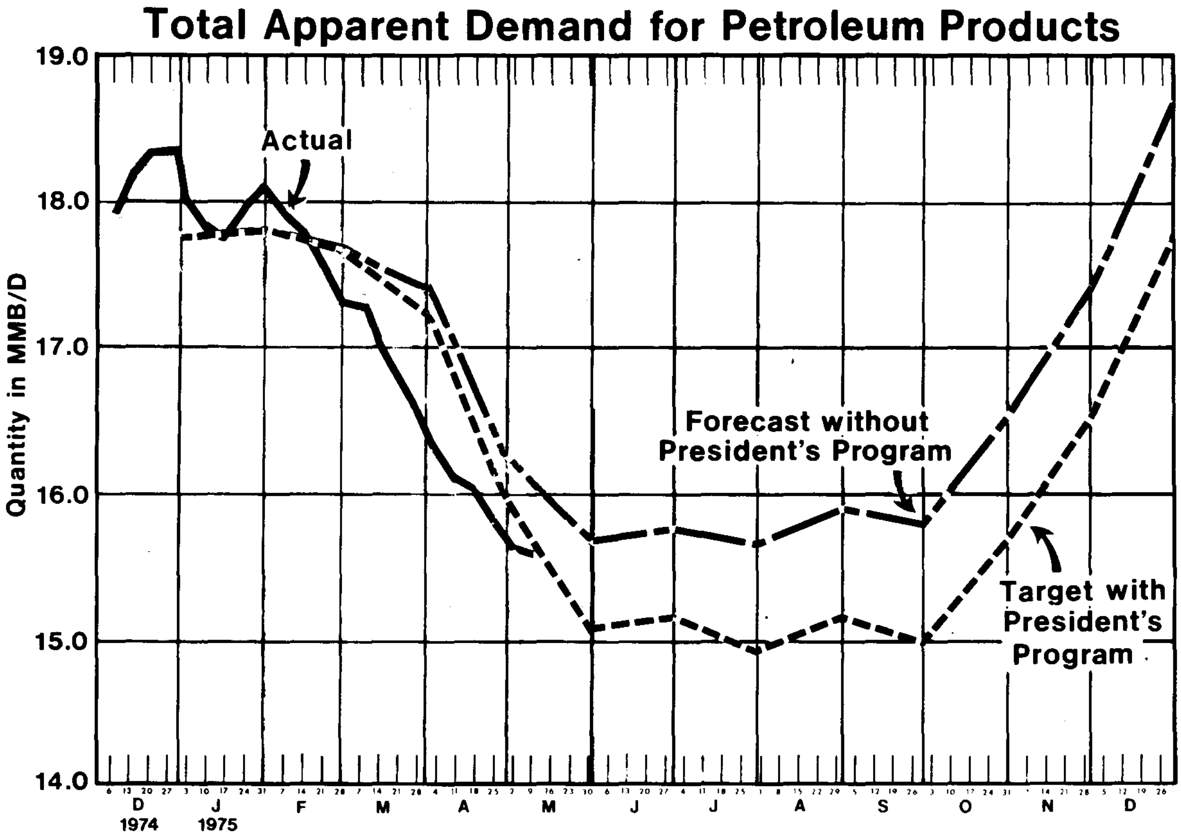
o Imports of crude oil and petroleum products for the 4 weeks ending May 9 were 5.12 million barrels per day, only 40,000 barrels per day above the target of 5.08 million barrels per day.

o Imports continue to account for about one-third (32.8%) of total U.S. demand for petroleum products.

o Crude oil imports at 3.29 million barrels per day constitute about two-thirds of total imports.

o When the revision to the forecast for total demand is completed (see note to Table 2) the import forecast is expected to be lowered by between one and two hundred thousand barrels per day (that is, about a 3 percent adjustment downward).

Table 2

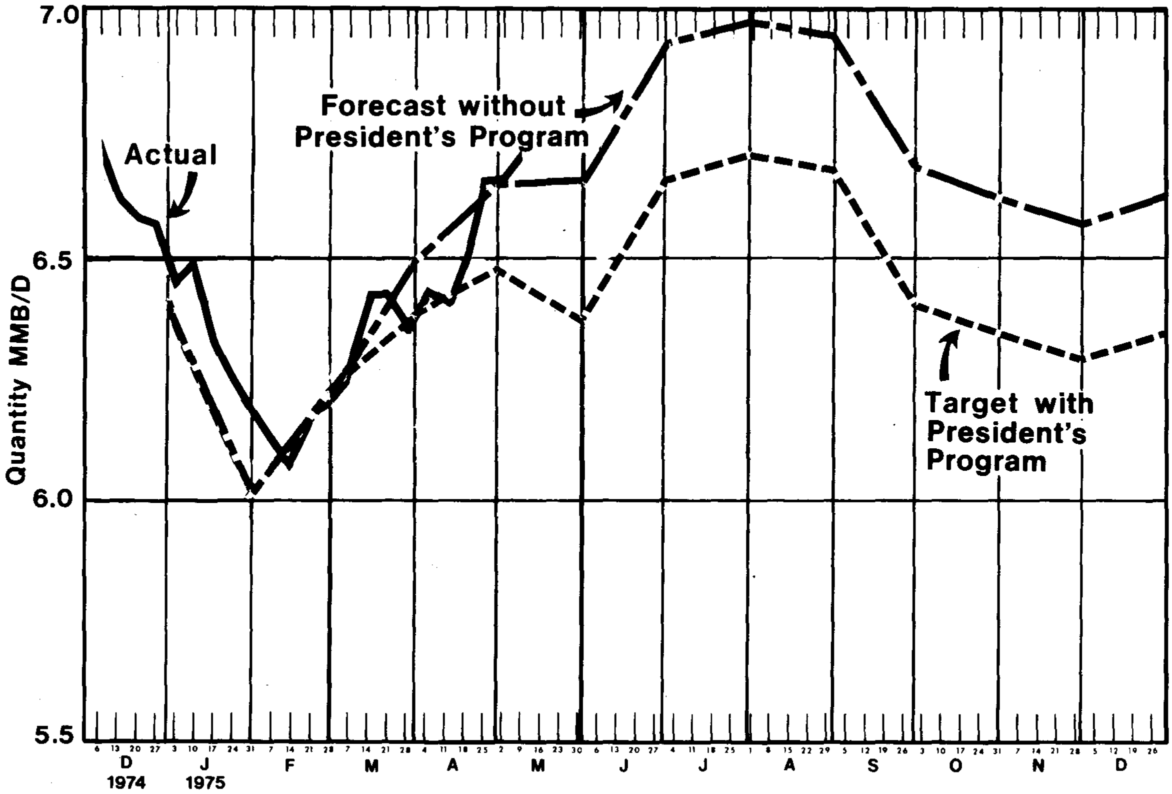


- o Total apparent demand for petroleum products during the 4 weeks ending May 9 was 15.62 million barrels per day, 150,000 barrels per day below the current estimate of the President's target of 15.77 million barrels per day, but 500,000 barrels per day below the current forecast of 16.12 million barrels per day.

- o While FEA's forecasts of demand for the major products have proven to be reasonably good, the forecasts for "other" products have been consistently low. When planned revisions to the forecasts are incorporated in the total, it is expected that both the forecast and the target for total demand will be reduced by between one and two hundred thousand barrels per day (that is, about a 1 percent adjustment downward).

Table 3

Apparent Demand for Motor Gasoline

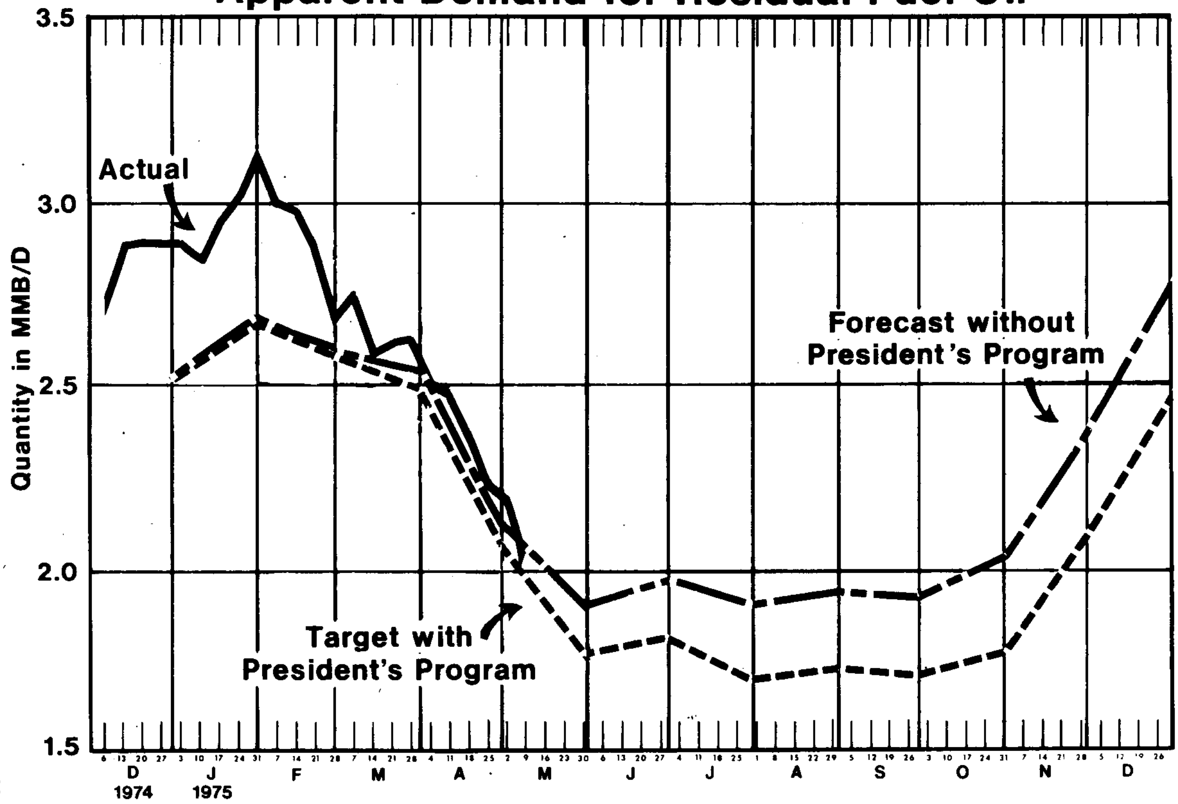


o Apparent demand for motor gasoline for the four weeks ending May 9 was 6.71 million barrels per day, 0.25 million barrels per day above the President's target level of 6.46 million barrels per day.

o The recent increase in demand for motor gasoline has reduced the record high stocks of February, to about the level of last year.

Table 4

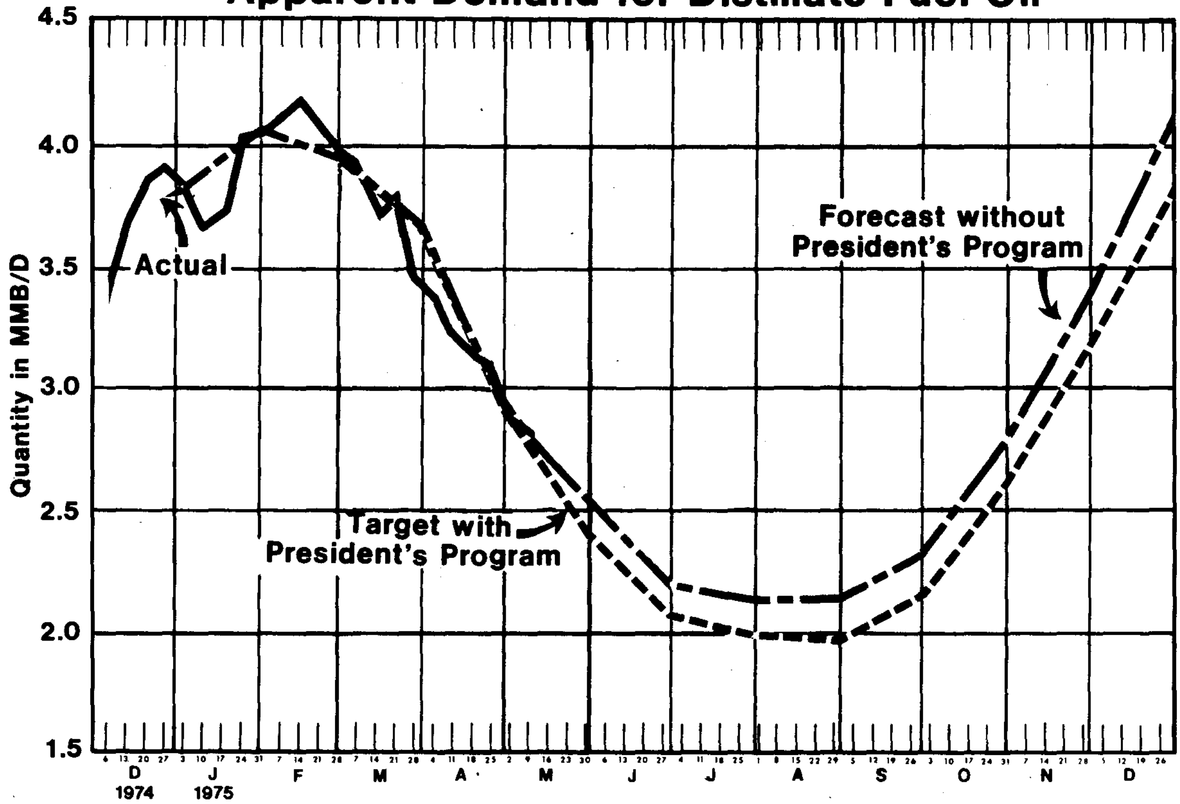
Apparent Demand for Residual Fuel Oil



o Apparent demand for the four weeks ending May 9 was 2.04 million barrels per day, only 50,000 barrels per day above the President's target.

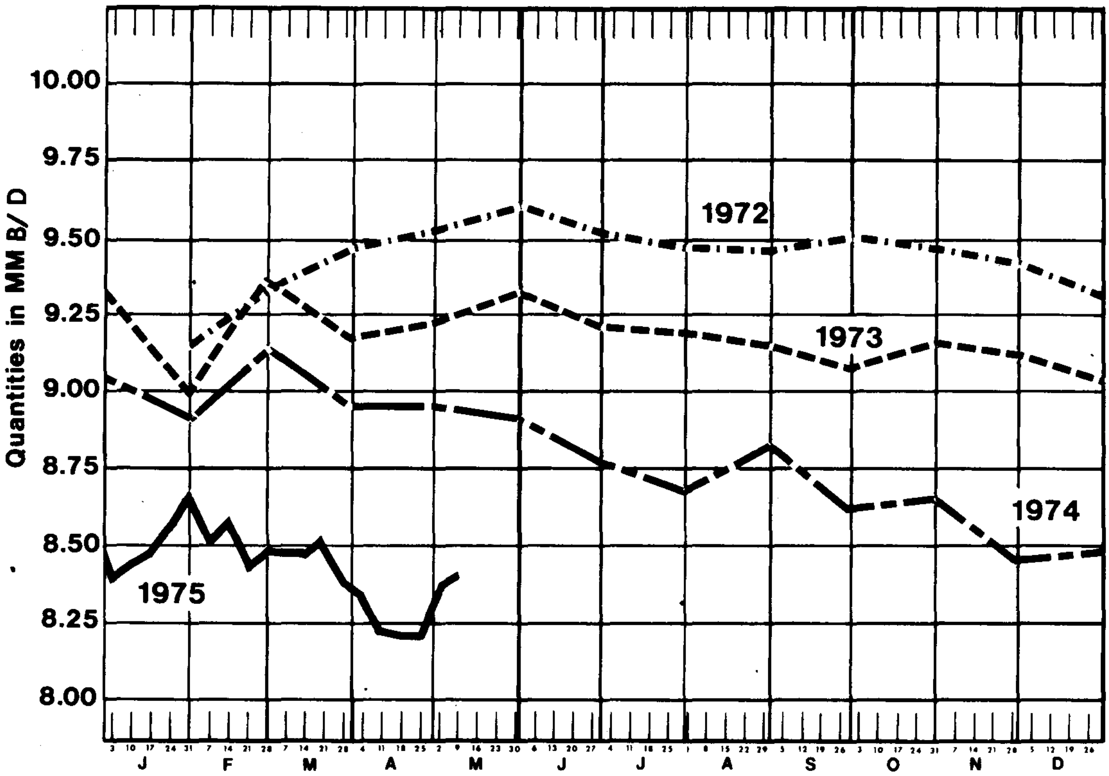
Table 5

Apparent Demand for Distillate Fuel Oil



o Apparent demand for the four weeks ending May 9 was 2.80 million barrels per day, equal to the 2.80 million barrels per day target.

Table 6
Domestic Crude Oil Production

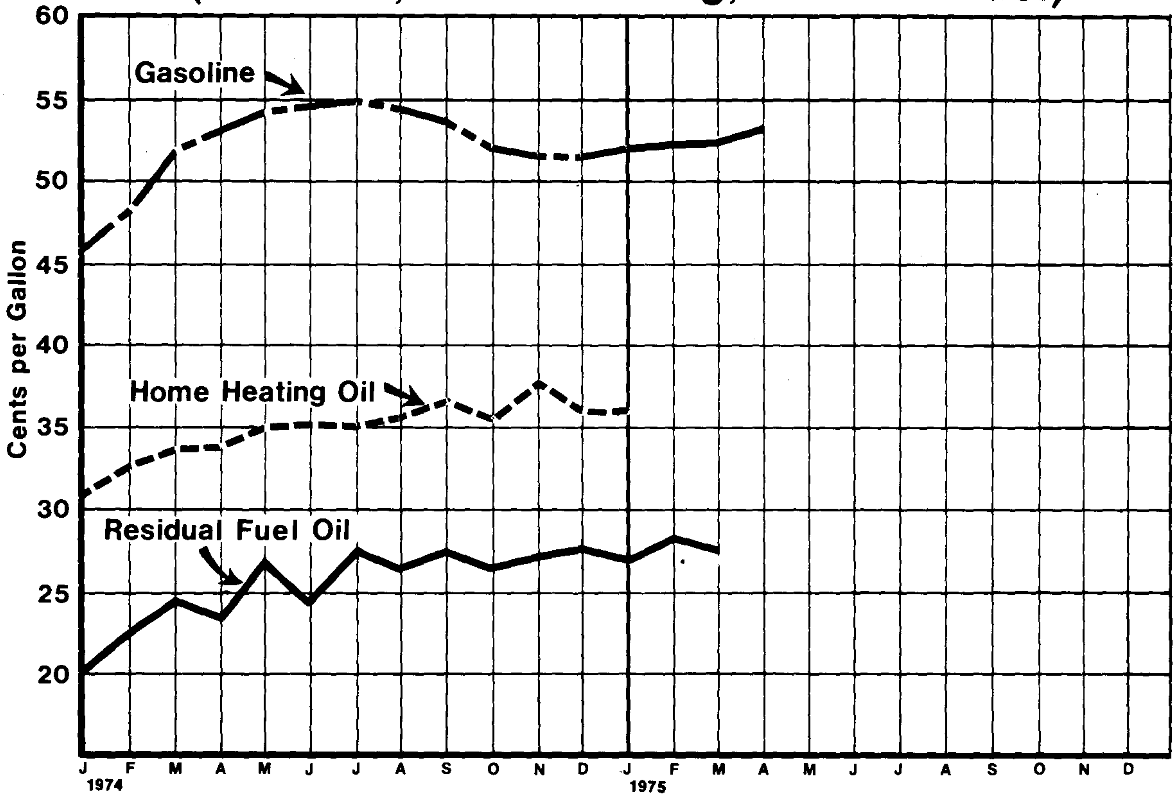


o Production for the four weeks ending May 9 shows an increase of 2 percent as compared with the four week period ending April 11. However, production to date this year is 5.8 percent below 1974.

Table 7

Retail Prices

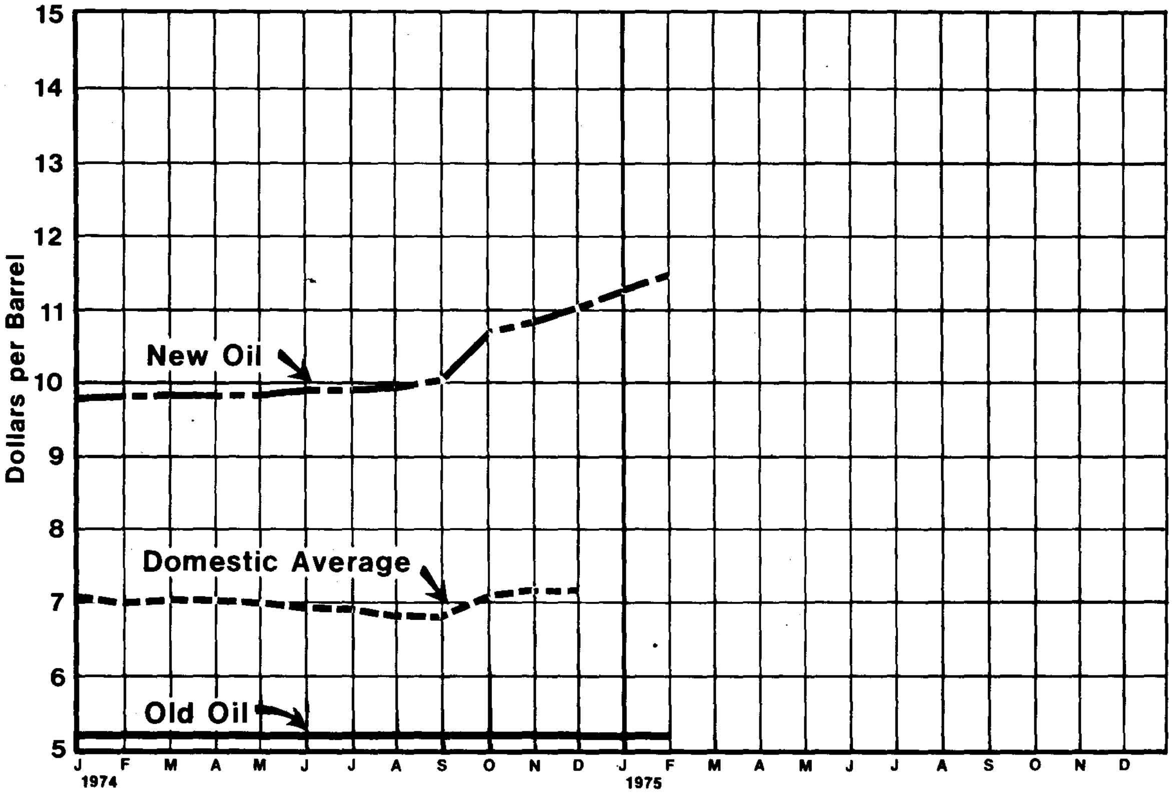
(Gasoline, Home Heating, Residual Fuel)



o Reflecting price increases by nearly all of the Nation's major retailers of gasoline, the average retail price of regular gasoline during April increased 0.9 cent per gallon to 53.3 cents per gallon.

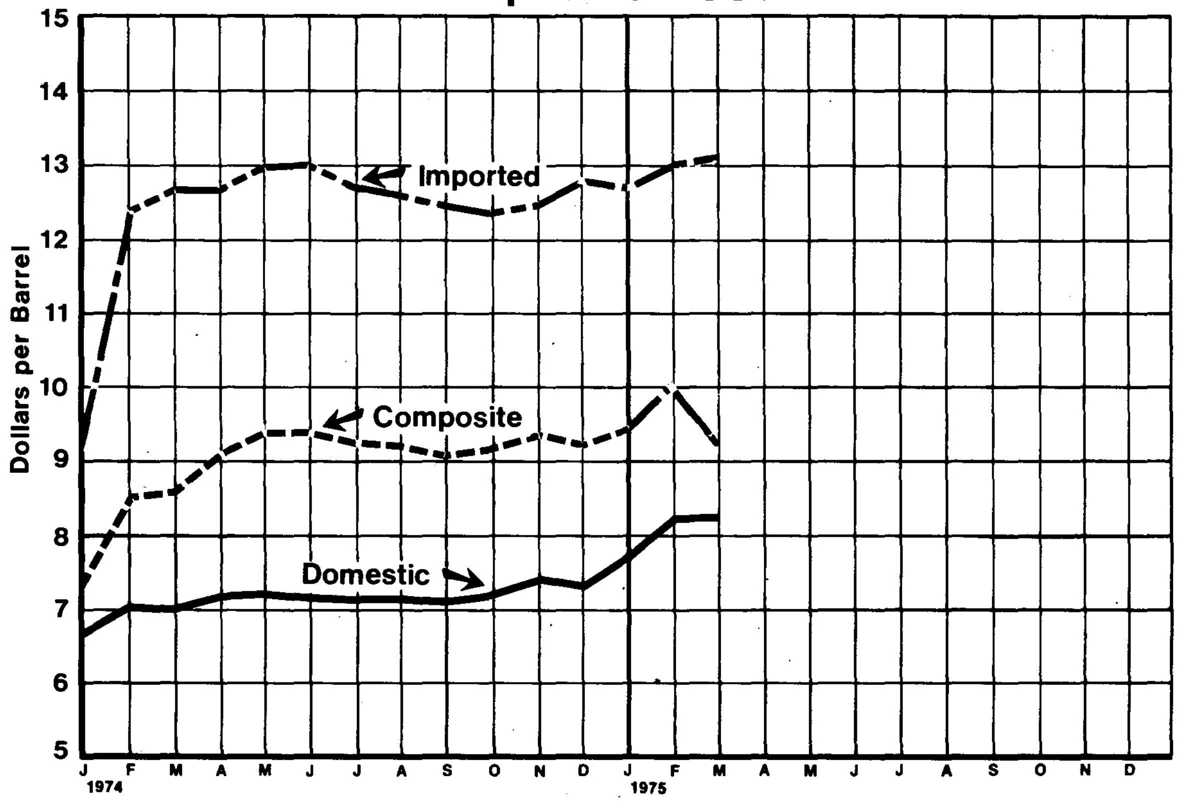
o During March the average residual fuel cost was 27.8 cents per gallon, a decrease of 0.7 cent per gallon from the February figure of 28.5 cents per gallon.

Table 8
Crude Oil Wellhead Price



(No new data since last report.)

Table 9
Crude Oil Refiner Acquisition Cost



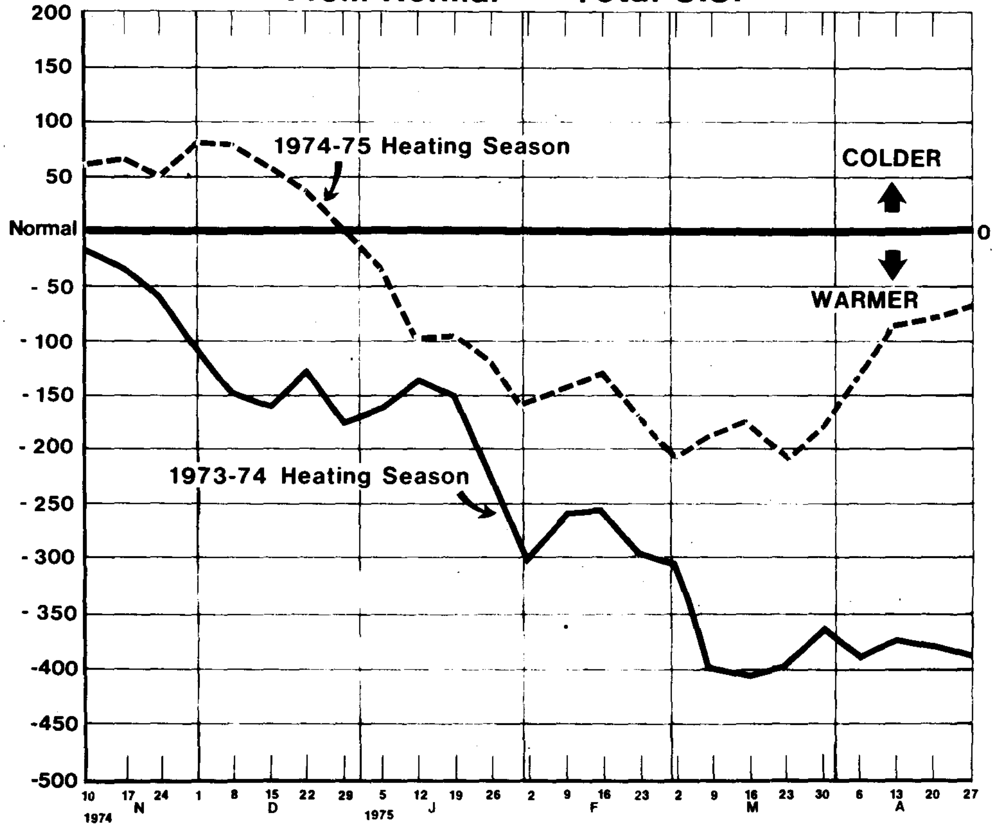
- o The cost of imported crude petroleum to refiners during March was $13.17 per barrel, an increase of 12 cents per barrel over the revised February figure of $13.05 per barrel and 40 cents per barrel over the January figure of $12.77 per barrel. The full impact of the dollar import fee on refiner acquisition cost was not reflected in February and March, due to accounting practices used for cost passthrough.

- o The average domestic refiner acquisition cost during March was $8.29 per barrel, unchanged from the revised February figure.

- o The composite cost of crude petroleum to refiners during March was down to $9.30 per barrel, a decrease of 79 cents per barrel from the revised figure of $10.09 per barrel. This large decline in the average cost was due to a large decrease in the percentage of higher priced imported crude purchased during March.

Table 10

Departure of Cumulative Distillate Heating Oil Degree-Days From Normal — Total U.S.



o For the 3-week period ended April 27, 1975, the weather in the continental United States was colder than normal (25.4 percent more distillate heating oil degree-days).

o So far in the 1974-75 heating season, the weather has been warmer than normal but colder than last year. Distillate heating oil degree-days for the U.S. have totalled 1.3 percent fewer than normal. A year ago, the distillate heating oil degree-days for the heating season were 8.0 percent fewer than normal.

o Through April 27, all PAD Districts except PAD II have accumulated less degree-days (warmer) this heating season than normal. The percentage changes are as follows:

PAD I	(East Coast)	-2.7
PAD II	(Mid-Continent)	+2.1
PAD III	(Gulf Coast)	-5.8
PAD IV	(Rocky Mountain)	-0.1
PAD V	(West Coast)	-2.9

DEFINITIONS

Apparent Demand -- Demand for products, in terms of real consumption, is not available; production plus imports plus withdrawals from primary stocks is used as a proxy for demand (consumption). Secondary stocks, not measured by FEA, are substantial for some products.

Actuals -- Four-week moving averages computed from the Weekly Petroleum Reporting System.

Forecast -- A petroleum product demand forecast is made, based on a projection of the economy, which would occur without the President's program, and on a projection of normal weather. The forecast is periodically revised to take account of actual weather and revised macroeconomic forecasts.

Target -- The Target incorporates reductions in consumption implicit in the President's energy policy, as given in the State of the Union Message. In addition it is assumed that:

- domestic production increases by 160 MB/D by the end of 1975 due to the development of Elk Hills.
- petroleum demand is reduced by 98 MB/D by the end of 1975 due to switching from oil to coal.
- petroleum demand due to natural gas curtailments ceases after May 1, 1975, due to the deregulation of new natural gas at the wellhead.
- price changes due to the President's policies are held constant in real terms at their May 1975 levels.

Degree-Days -- The number of degree-days in one day is the number of degrees by which the mean temperature for the day is below 65° F. Statewide averages for degree-days are based on population weights. These statewide averages are then aggregated into P.A.D. Districts and the national average using a weighting scheme based on each State's consumption of fuel oil per degree-day, thereby relating the impact of the weather to distillate heating oil demand. Note that "above normal" degree-days correspond to "below normal" temperatures.

D

TAB D

Major International Events

Major International Events

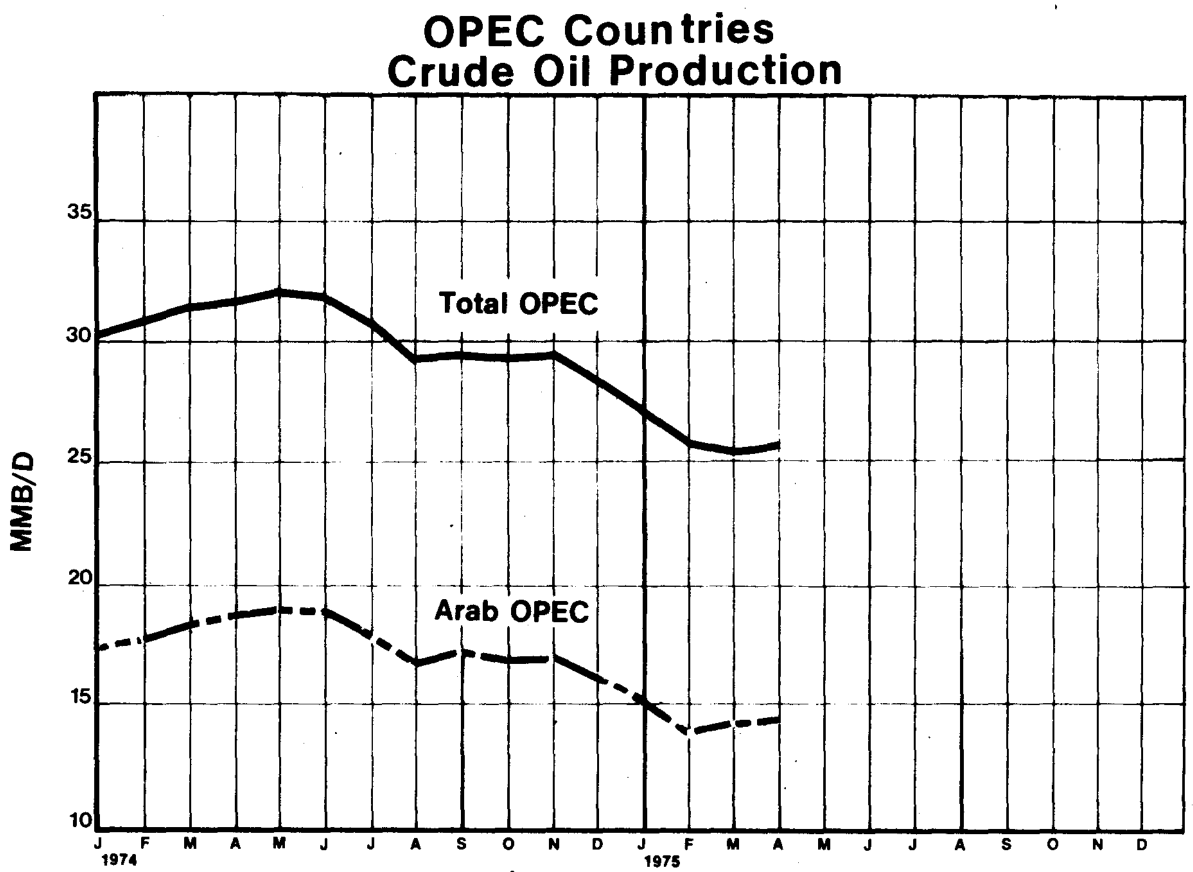
- Speaking to reporters after a recent Arab Ministers Conference, Saudi Arabia's Sheikh Yamani said that the next June OPEC meeting will consider linking the price of oil to some yardstick other than the U.S. dollar; if adopted, he asserts the move would be nothing more than a fixing of the oil price and should not be taken as a price rise.

- In an apparent change in policy, Mexico declared its willingness to join OPEC. President Echeverria told reporters that if Mexico is formally invited to join, it will do so. Until now, Mexico has only tentatively indicated its willingness to join OPEC in an observer status.

- The Shah of Iran stated that he expects an increase in oil prices at the September OPEC meeting. Despite the fact that world inflation has been averaging less than 10 percent recently, the Shah claims that a 35 percent reduction in purchasing power is the reason for the proposed end to a nine-month OPEC price freeze.

- Gulf Oil Company has encountered difficulties, particularly in Latin America, following the revelation that Gulf had made political payments amounting to $4 million in South Korea and $360,000 in Bolivia. Peru nationalized Gulf's retail outlets in that country in protest, and Bolivia has initiated action in its courts against Gulf, placing Gulf's representative there under house arrest.

- Canada has announced an 80 cent decrease in the export tax charged on crude exported to the U.S., but at the same time announced that the price of natural gas exported to the U.S. will increase by 60 percent before the end of the year.



- OPEC production, which has been declining since 1974, is expected to rise this summer. The decrease in OPEC production in recent months, which is usually attributed to the fall in world oil demand, may also have been exacerbated by a drawdown in inventories, especially in Western Europe. To meet next winter's demand, some of these stocks will have to be restored. As a result, world crude production (principally OPEC production) is expected to rise between 2 and 4 million barrels per day from current production levels.

A

A G E N D A

ENERGY MEETING - CAMP DAVID
June 7 and 8

SATURDAY

1.	Introduction and statement of purpose	9:00 - 9:15	ZARB
2.	ERDA Briefing		
	A. ERDA Overview	9:15 - 9:45	SEAMANS
	B. ERDA R&D Plan	9:45 - 11:45	ERDA
	C. ERDA Issues	12:45 - 4:15	ERDA
	Synthetic Fuels Technology		
	Liquid Metal Fast Breeder Reactor		
	Light Water Reactor		
	Fuel Cycle (Uranium Enrichment)		
	Fusion, solar, geothermal		
3.	Conservation Plan	4:15 - 5:15	FEA/ERDA
		7:00 - 8:00	FEA/ERDA
4.	International Situation	8:00 - 9:00	STATE
5.	Minimum Safeguard Price	9:00 - 10:00	STATE

SUNDAY

1.	Status of President's Proposals and Major Unresolved Legislative Issues	8:30 - 9:30	ZARB
2.	Major Issues		
	A. Nuclear Power	9:30 - 10:30	NRC
	B. OCS Development	10:30 - 11:15	DOI
	C. Natural Gas Curtailments	11:15 - 12:00	FEA
	D. Utility Financing Alternatives	12:00 - 1:00	FEA

B

Monthly Energy Review

April 1975

Federal Energy
Administration

National Energy
Information Center

Washington
D.C. 20461

Contents

Beginning with the March 1975 issue, this periodical will be distributed on a subscription basis from the following:

Subscriptions
National Technical Information Service
5285 Port Royal Road
Springfield, VA 22161

For addresses inside the United States, the cost will be \$36 per subscription (12 issues). For addresses outside the United States, the cost will be \$50 per subscription.

Feature Article

NUCLEAR POWER

Although total consumption of electricity did not increase during 1974, the generation of electricity from nuclear power continued to experience rapid growth, rising 32 percent above the level for 1973 (Figure 1). Because of the increasing importance of nuclear power, we introduce in this issue of the *Monthly Energy Review* a section that features statistics on nuclear power. After basic facts about nuclear fission and powerplants are presented, the history of nuclear electric power generation and its related fuel industry are described. Finally, information is presented on the environmental and health aspects of nuclear power.

NUCLEAR POWERPLANTS

In a nuclear plant, energy is obtained from the fission (splitting) of the uranium or plutonium atomic nucleus into two smaller nuclei. The combined mass of the fission products is about 0.1 percent less than the mass of the original nucleus. The extra mass, m, is converted into thermal energy, E, as given by Einstein's famous equation, $E=mc^2$, where c is the speed of light.

Two features of nuclear fission make it useful as an energy source: (1) an enormous amount of energy is released per weight of fuel consumed (74 million Btu per gram of material fissioned, the equivalent of burning 3 tons of coal) and (2) fission is self-perpetuating because neutrons[1] both induce fission and are produced by fission. Since only one neutron is needed to cause one fission and several neutrons are released from each fission, a "chain reaction" can occur which sustains the nuclear burning.

All nuclear power reactors have some common elements:

- *Reactor core*—the fuel material and supporting structures in which the primary heat production from fission occurs;
- *Control rod*—device which absorbs the excess fission neutrons when inserted into the reactor core, thus controlling the chain reaction;
- *Moderator*—material which slows down the "fast" (energetic) neutrons, causing them to lose energy and become more likely to initiate the next fission;
- *Coolant*—fluid which transfers the core heat to the steam generator;
- *Steam generator*—device which utilizes the heat from the coolant to generate steam for driving a turbine generator.

Most U.S. reactors are of the light-water reactor (LWR) type in which the coolant and moderator are the same material, ordinary water. There are two classes of LWR's manufactured in the United States, the boiling-water reactor (BWR) manufactured by General Electric and the pressurized-water reactor (PWR) manufactured by Babcock and Wilcox, Combustion Engineering, and Westinghouse (Figure 2). The steam generator in the BWR is the reactor core itself—water is boiled in the core to produce steam which directly drives the turbine. In the PWR, the heated moderator-coolant water is kept as a liquid under pressure and fed to a steam generator outside the reactor core. Steam is then formed in a separate secondary system in the steam generator by transfer of heat into the secondary system.

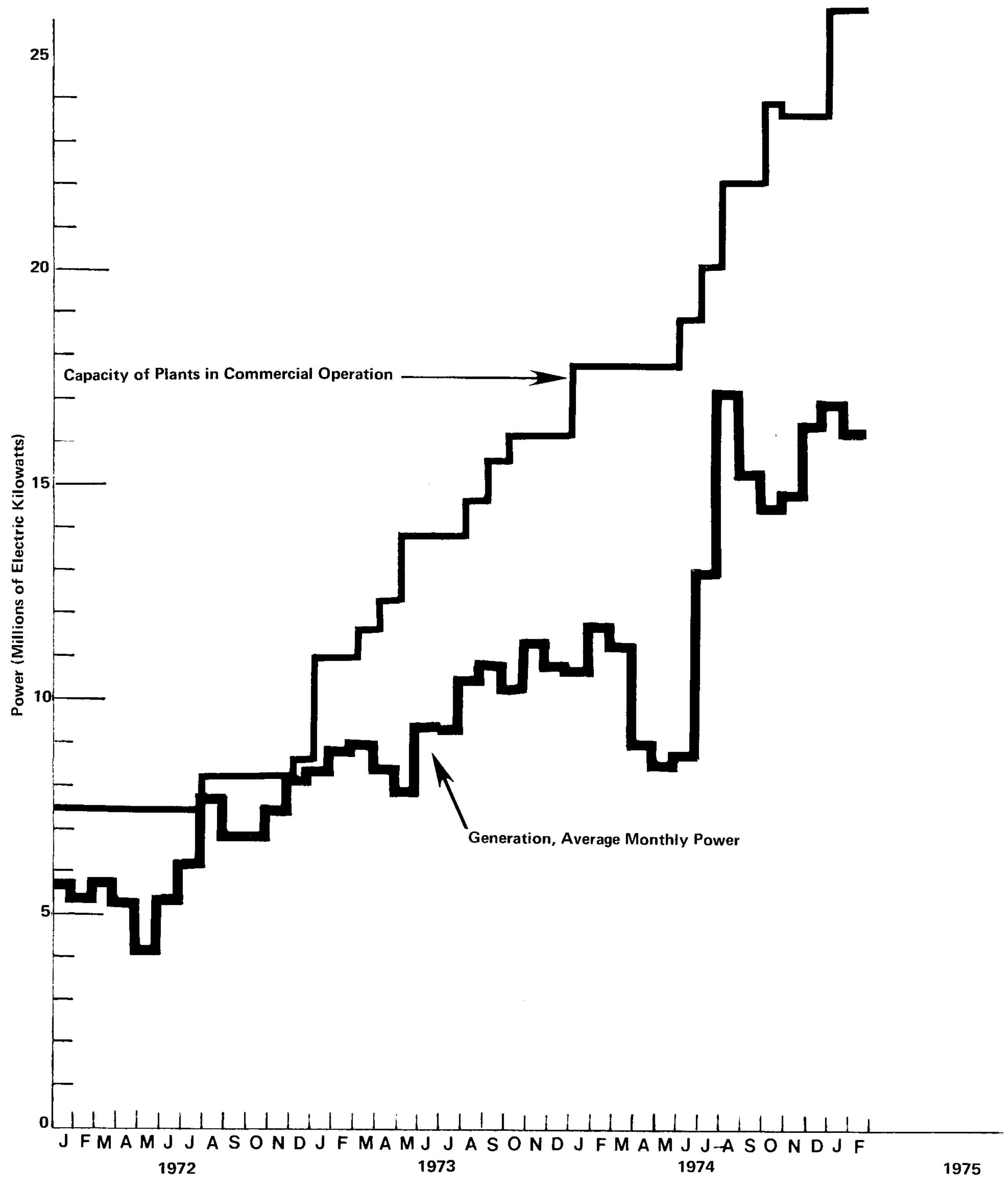
An alternative concept to the LWR is employed by General Atomic in its high-temperature gas-cooled reactor (HTGR). The HTGR moderator is graphite, and the coolant is helium gas under high pressure.

The licensing and construction of a nuclear plant takes approximately 8 years, as shown in Figure 3. 1974 was especially significant because of severe setbacks in plans for future construction. In the last half of 1974, construction deferrals were experienced by 94 of the 194 plants on order, and 14 more were canceled completely. The deferrals represent a loss of over 1 trillion kilowatt hours, which is half the total U.S. electricity generation for 1974. The principal reasons cited for these deferrals and cancellations were difficulty of financing new construction and uncertainty in future requirements due to low growth in electricity demand in 1974. Forecasts of nuclear power growth, based on announced industry plans at the end of the first quarter of 1975, are presented in Table 1. Statistics on announced deferrals and cancellations will be presented in future issues of the *Monthly Energy Review.*

Because large amounts of residual radioactivity are produced by reactor operation and human exposure to such radioactivity can be harmful, a great deal of attention is paid by the industry and the Nuclear Regulatory Commission to safety features for confinement of this radioactivity. The worst conceivable accident for an LWR is the so-called "loss of coolant accident." If all the coolant water in the core is lost, the nuclear fissioning can no longer occur since the water is also needed to moderate the neutrons. However, radioactive decay of the residual wastes in the fuel generates

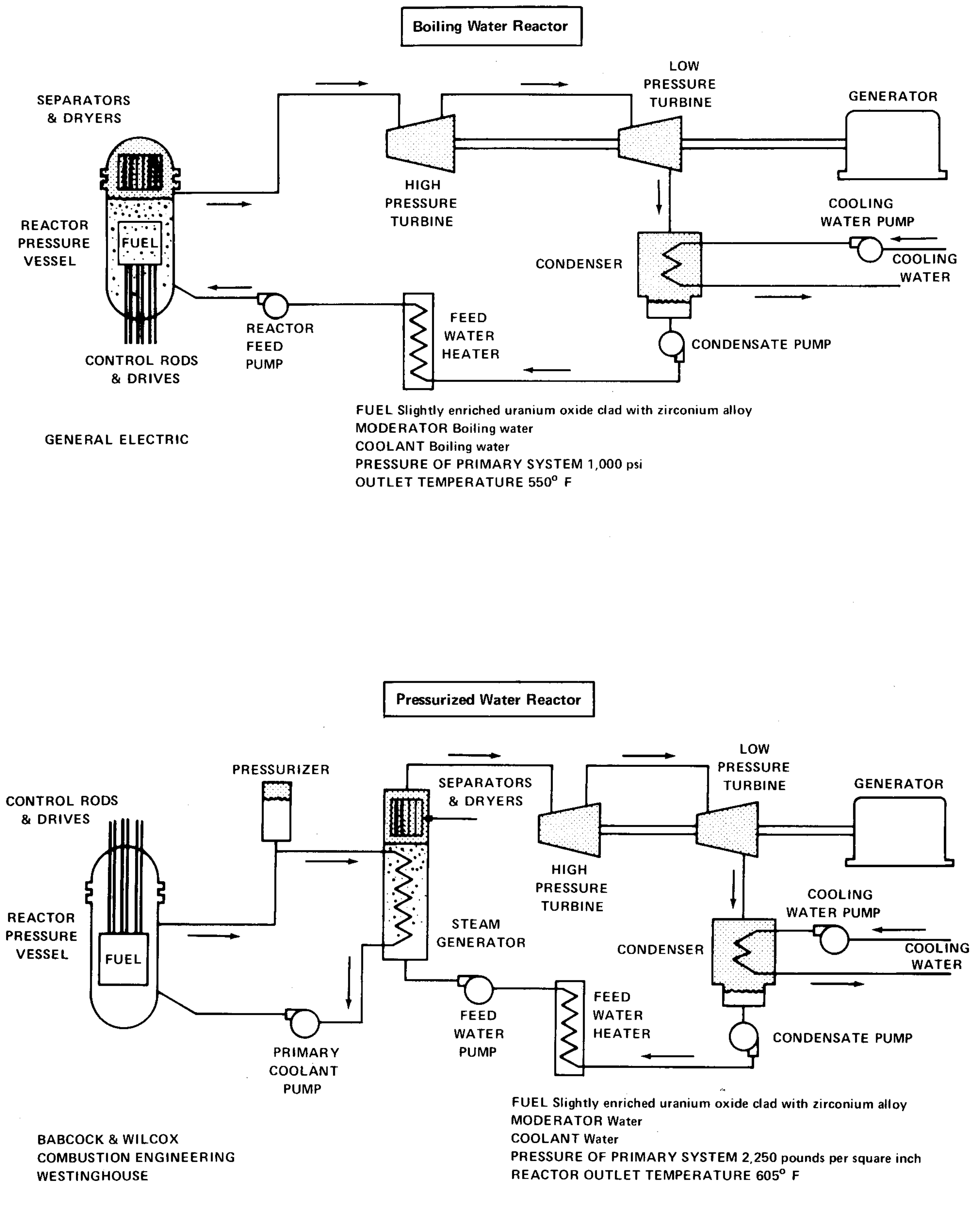
[1] See Explanatory Note 1 for a description of neutrons.

Figure 1. U.S. Nuclear Electric Power Generation and Capacity, 1972 to Present



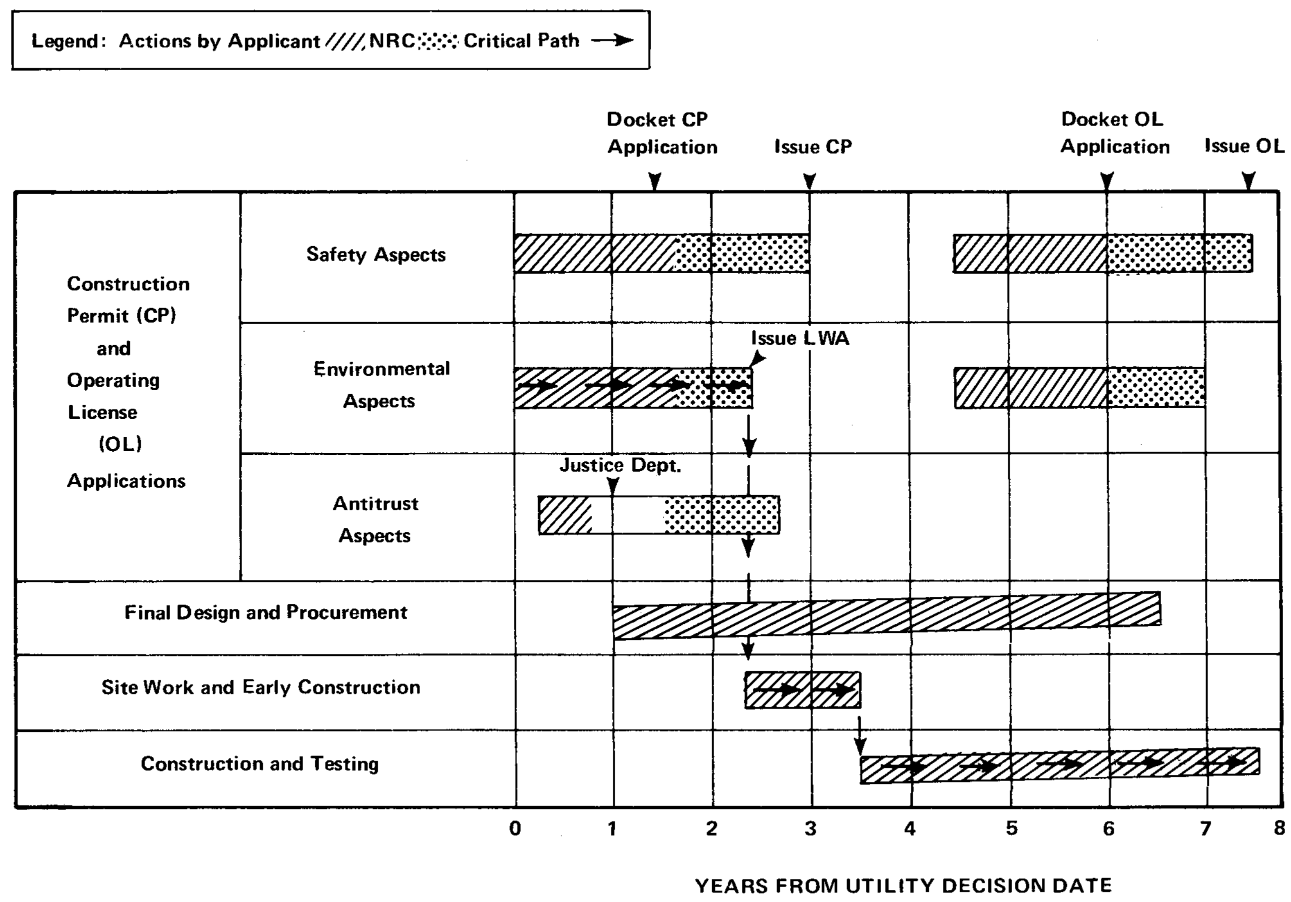
Source: Capacity—U.S. Nuclear Regulatory Commission; Generation—Federal Power Commission.

Figure 2. Schematic Diagrams of LWR Reactors



Source: The Nuclear Industry, 1974 (Report No. WASH 1174–74, U.S. Atomic Energy Commission).

Figure 3. Time Required From Conception to Operation of Nuclear Plants
(With Limited Work Authorization Procedure)



Source: U.S. Nuclear Regulatory Commission (NRC).

Table 1. Projected Installation of U.S. Nuclear Power Reactors

Year of Expected Commercial Operation	Number of Reactors: Annual	Number of Reactors: Cumulative	Capacity (Net electrical megawatts): Annual	Capacity (Net electrical megawatts): Cumulative
1975	17	61	14,120	43,170
1976	7	68	6,677	49,847
1977	7	75	6,749	56,596
1978	8	83	7,823	64,419
1979	10	93	10,905	75,324
1980	18	111	19,279	94,603
1981	22	133	23,814	118,417
1982	24	157	27,410	145,827
1983	22	179	24,484	170,311
1984	21	200	22,687	192,998
1985	13	213	14,612	207,610

Source: *Nuclear Industry Status,* Nuclear Assurance Corporation Quarterly Report, April 1975.

so much heat that the reactor core could melt, with possible release of radioactivity to the environment.

An early study[2] by the Atomic Energy Commission (AEC) indicated that the consequences of such an accident could be catastrophic. Accordingly, Congress enacted the Price-Anderson Act which contained provisions for insuring and indemnifying the public against a nuclear accident. The Act expires in 1977, and attempts at its renewal are being tied to the completion of an ongoing technical study of reactor accident probabilities, the "Rasmussen study." A draft form of the study's findings[3] has generated a great deal of controversy and will probably become the focal point of debate in the

[2] Report No. WASH-740, U.S. Atomic Energy Commission.

[3] *Reactor Safety Study, An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants,* Report No. WASH-1400, U.S. Atomic Energy Commission (August 1974).

present Congress when renewal of the Price-Anderson Act is considered.

The key indicator for operating reliability is the capacity factor, defined as the ratio of the nuclear plant's generated electricity to its maximum design capability. The target of the nuclear industry has been an 80-percent capacity factor; however, the industry average has been approximately 60 percent for the past several years. Although fossil plants of comparable size to the newest nuclear plants have experienced similar reliability problems, nuclear plants are more capital intensive, and thus shutdowns more severely affect the cost of producing electricity.

Table 2 summarizes the international generation of electricity from nuclear power. This table shows that in 1974 the United States generated 48 percent of the non-Communist world's nuclear electricity, but our plants operated at lower capacity factor than the world average. Canada's CANDU reactors (pressurized heavy-water[4] moderated and fueled with non-enriched uranium) performed quite well in comparison to all others, while the gas-cooled, graphite-moderated reactors of Great Britain performed only slightly better than our light-water reactors.

Monthly statistics on installed capacities, generated electricity, and capacity factors will be presented in the nuclear section of the *Monthly Energy Review.*

THE NUCLEAR FUEL CYCLE

Several physical and chemical steps are necessary to process the fuel and radioactive wastes of a nuclear powerplant. The collective generic term for these processes is the nuclear fuel cycle, illustrated in Figure 4. Each step is described below. Table 3 provides summary information on existing and potential fuel cycle facilities. Table 4 provides historical data.

Mining—Uranium-bearing ore is removed from the earth in underground or open-pit mines by methods similar to those used for other metal ores. Uranium ores are low-grade, with an average uranium content of approximately 0.2 percent. Enriching of imported uranium for commercial power use is currently prohibited, but will be phased-in starting in 1977. Known U.S. reserves of uranium oxide (U_3O_8) in the $15-per-pound cost category are in the neighborhood of 400,000 tons. In the $30-per-pound category, known reserves are 600,000 tons. The latter could produce approximately 2.4 million megawatt-years of electricity which is equivalent to almost 11 years of current electrical production in the United States from all fuels. Thus, the extent of our uranium resources amy be the growth-limiting factor for future U.S. nuclear power production. The Energy Research and Development Administration (ERDA) is currently engaged in a program (National Uranium Resource Evaluation Program) to obtain comprehensive geological data needed to determine the size of our uranium resources.

Milling—Ores are crushed and ground, and the uranium chemically extracted. The uranium fraction is converted to U_3O_8 ("yellow-cake") for shipment; the remainder of the ore is a waste product called mill tailings.

Conversion—U_3O_8 is chemically converted to the more volatile hexafluoride, UF_6, which is feed for the subsequent enrichment stage.

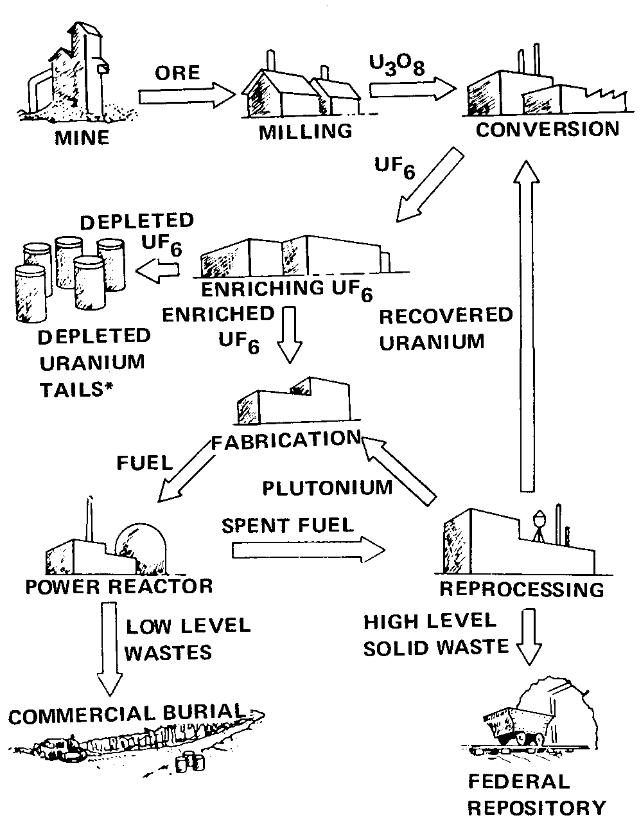
Table 2. Commercial Nuclear Power Generation in Major Non-Communist Countries

Country	Number of Reactors	Gross Electricity Generation Year 1974	Gross Electricity Generation January 1975	Capacity Factor Year 1974	Capacity Factor January 1975
		In billion kilowatt hours		In percent	
Japan	8	15.08	1.52	61	52
Canada	5	15.41	1.17	74	65
Federal Republic of Germany	7	11.16	1.49	57	73
France	10	14.75	1.90	57	84
Great Britain	29	33.00	2.83	61	62
Italy	3	3.42	0.37	61	80
Spain	3	6.94	0.72	75	88
Switzerland	3	7.04	0.76	76	96
United States	42	98.02	14.97	57	59
Totals	110	204.82	25.73	63	63

Source: Nucleonics Week Magazine.

[4] See Explanatory Note 2 for description of heavy-water.

Figure 4. The Nuclear Fuel Cycle



*NOT REQUIRED FOR REACTOR BUT MUST BE STORED SAFELY. HAS VALUE FOR FUTURE BREEDER REACTOR BLANKET.

Source: Adapted from the Nuclear Industry, 1974. (U.S. Atomic Energy Commission Report No. WASH-1174-74).

Enrichment—Natural uranium consists of two isotopes,[5] U-238 and U-235. If natural uranium were used in an LWR, the non-fissionable U-238 and the coolant-moderator water would absorb so many neutrons that a chain reaction could not be sustained. To maintain the chain reaction, the uranium fuel must have a greater percentage of fissionable U-235. The process of increasing the percentage of U-235 in the uranium fuel is called enrichment.

The technique presently used for enriching consists of heating the UF_6 to its gaseous state and forcing it to diffuse through a large number of porous barriers. Because the fissile U-235 has a smaller atomic weight than non-fissile U-238, it diffuses slightly faster and the resultant product has a higher U-235 content. The net result of this process is the separation of the natural uranium into two groups, one enriched in U-235 and the other depleted in U-235 ("enrichment tails"). The energy expended in enrichment (which determines its cost) is called "separative work" and is measured in grams of Separative Work Units, or SWU (see Definitions). Figure 5 shows the relationships among SWU, product and tails assays, and the energy and material requirements for enrichment of typical LWR fuel.

[5] See Explanatory Note 5 for discussion of uranium isotopes.

Although ERDA is actively expanding the enriching capability of its three existing plants, the projected demand overtakes ERDA's projected capacity sometime during the early 1980's. As a result, ERDA has been preproducing enriched uranium and encouraging private ventures in both the standard gaseous diffusion enrichment process and the newly developed gas centrifuge process. Although economically undemonstrated at present, the centrifuge process warrants further consideration, since a centrifuge plant would require only 10 percent of the electric power used by a diffusion plant for the same amount of separative work.

Fabrication—Enriched UF_6 is changed to uranium dioxide (UO_2), formed into ceramic pellets, and sealed in corrosion-resistant zircalloy or stainless steel tubes. The loaded tubes, called elements, are mounted in assemblies for ease in loading and unloading at the reactor.

Power reactor—With the fuel assemblies in place, the reactor is ready for operation. Table 5 shows design characteristics of fuel flow through typical BWR and PWR reactor cores. Note that about one-fourth to one-third of the core is refueled each year.

It is mentioned in Explanatory Note 5 that U-238 can absorb a neutron and form fissile Pu-239. This process occurs on a significant scale inside the reactor core because of the presence of large numbers of neutrons and U-238 nuclei. In fact, the subsequent fissioning of Pu-239 formed within the reactor core accounts for about one-third of the energy derived from the nuclear fuel.

The reactor must be refueled before all the U-235 and Pu-239 are fissioned because of the buidup of certain fission products which "poison" the reactor by absorbing so many neutrons that the chain reaction can no longer be sustained.

Reprocessing—Spent (discharged) fuel from reactor operation is shipped to reprocessing plants for chemical separation into its three components—uranium, plutonium, and radioactive waste. The recovered uranium has a higher percentage of U-235 than natural uranium (see Table 5), and thus makes excellent enrichment feed material. The plutonium serves as a direct substitute for U-235 when blended with uranium. This uranium and

Table 3. Nuclear Industry Facility Summary*

Phase of Nuclear Fuel Cycle	Industry Capability: Number of Facilities	Maximum Capacity	Reactors Supported**	Planning and Construction: Plant Size Range	Lead Time (Years)	Cost (Dollars per kWe)
Mining and Milling	200 mines 16 mills	13,800 MTU/year	90	400-1200 MTU/year	***8-10	20-40
Conversion	2	17,200 MTU/year	65	4,500-12,700 MTU/year	4	1-2
Enrichment	3	12.3 million SWU/year	120	0.6-9 million SWU/year	†5-8	33
Fabrication	5	2,900 MTU/year	85	150-1,150 MTU/year	4	2-3
Electricity Generation	††52	34,800 MWe	––	325-1300 MWe	8	600-720
Reprocessing	1	0	0	300-1500 MTU/year	8-7	11

*See Explanatory Notes 3 and 4 for discussion of units of measure.
**1000 MWe size. Derived from data provided in Report No. WASH-1174-74 (U.S. Atomic Energy Commission).
***Lead time includes time for exploration activity necessary to determine proved reserves. Lead time for construction of a mill is 2 to 3 years.
†Gaseous diffusion plant assumed.
††Includes plants in start-up testing.
Source: U.S. Nuclear Regulatory Commission and industry sources.

Table 4. Historical Data on the Nuclear Fuel Cycle*

	Milling: Yellow-Cake Sales	Conversion: Sales	Enrichment: Domestic	Foreign	Stockpile	Fabrication: Receipts	Shipments	Production	Powerplant: Fuel Discharges
1972									
1st Quarter	NA	NA	254	266	NA	NA	NA	286	110
2nd Quarter	NA	NA	402	289	NA	195	144	43	77
3rd Quarter	NA	NA	1,316	567	NA	445	197	524	24
4th Quarter	NA	NA	703	748	NA	319	415	163	25
Total	NA	NA	2,675	1,870		NA	NA	1,016	236
1973									
1st Quarter	5,150	7,300	597	704	NA	277	102	136	36
2nd Quarter	10,690	6,700	1,161	2,094	NA	373	162	164	73
3rd Quarter	1,380	3,440	942	9,210	NA	310	182	218	30
4th Quarter	13,800	19,000	1,188	689	15,380	404	308	483	16
Total	31,020	36,440	3,888	12,697		1,364	754	1,001	155
1974									
1st Quarter	2,040	5,120	926	531	17,290	340	526	245	71
2nd Quarter	3,600	3,790	1,424	805	18,000	331	357	26	139
3rd Quarter	4,390	2,640	1,165	375	19,690	412	263	360	67
4th Quarter	12,460	22,840	738	1,154	21,160	501	275	226	174
Total	22,490	34,390	4,253	2,865		1,584	1,421	857	451

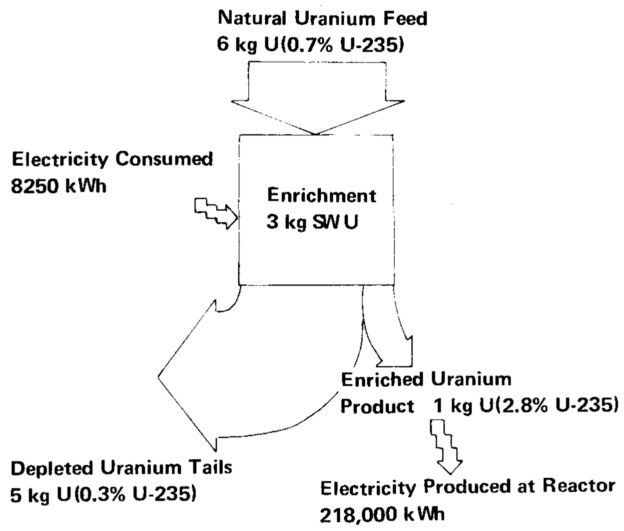
*All units are MTU except those for enrichment, which are MT-SWU. See Explanatory Note 3 for discussion of units.
NA = Not available.
Source: Enrichment statistics are from Enrichment Branch, ERDA, Oak Ridge, Tennessee; all others are from *Nuclear Industry Status,* Nuclear Assurance Corporation Quarterly Reports.

plutonium recycling can reduce the natural uranium feed requirement by 12 percent and the enrichment work requirement by 15 to 25 percent.

The economic and resource conservation benefits of recycling are offset by other factors. Plutonium is as toxic per unit of weight as nerve gas. Although the uranium used in power reactors is not of sufficiently high enrichment for weapon fabrication, a nuclear bomb can be made from relatively small amounts of plutonium. Thus, extreme caution must be taken in handling and transporting plutonium. (These issues are discussed further in the draft environmental statement on plutonium recycle.[6])

[6] *Generic Environmental Statement on Mixed-Oxide Fuel (GESMO),* Report No. WASH-1327, U.S. Atomic Energy Commission (August 1974).

Figure 5. Energy and Material Balance in Enrichment



Source: U.S. Atomic Energy Commission.

Recycling in LWR's has been done only on a small scale to verify that there are no detrimental effects on reactor operation. Recovery of uranium and plutonium in anticipation of recycling has occurred on a larger scale, but today there are no reprocessing plants operating, and thus facilities for storage of spent fuel are becoming filled to capacity. In fact, some reactors are in danger of having to shutdown in the future because of lack of space to store their discharged fuel.

One of the key policy decisions that must be made by the Nuclear Regulatory Commission involves plutonium recycling. If it is determined that the benefits of recycle do not outweigh the societal risks, then future requirements for mined uranium and enrichment are affected as well as the need for reprocessing plants. Also affected is the future of the breeder reactor discussed next.

THE LIQUID METAL FAST BREEDER REACTOR (LMFBR)

A fast reactor is one which has no moderator. Fissioning is thus induced by "fast" neutrons produced from previous fissions which have not been slowed down. The probability for fertile U-238 absorbing a neutron to form Pu-239 is greater for fast neutrons than for slow ones. When a "blanket" of U-238 is placed around the core of a fast reactor, it is known as a "breeder" reactor because more fissile atoms are formed in the blanket than are consumed in the core. The use of breeder reactors would extend the effective life of our uranium resources because more than 50 percent of the U-238 could be utilized for fuel instead of 0.3 percent which is utilized with the present LWR technology. However, since the Pu-239 produced in the blanket must be separated from the U-238, all the problems of LWR plutonium recycling are magnified several fold.

France has operated a 250-megawatt fast breeder for over a year and is developing larger plants. Other countries with fast breeder programs are Russia, West Germany, Japan, and the United States.

A demonstration fast breeder reactor, with liquid sodium metal as the coolant, is being built on the Clinch River in Tennessee. The initial cost estimate for the 450-megawatt plant was about 500 million dollars, half of which was committed by Commonwealth Edison Company and the Tennessee Valley Authority, and the other half by the AEC (now ERDA). The cost estimate has now escalated to 1.4 billion dollars, bringing the project under close Congressional scrutiny and forcing a management reorganization of the project. Thus, the future of the Clinch River Breeder Reactor, and of the breeder program in general, is in jeopardy pending resolution of financial problems and the plutonium recycle question.

WASTE DISPOSAL AND ENVIRONMENTAL EFFECTS

There are two types of wastes from nuclear power: waste heat and nuclear radiation. A typical large nuclear plant has a heat-to-electricity conversion efficiency of 32.0 percent; in other words, 68 percent of the heat generated is wasted. (For comparison, the conversion efficiency for coal-fired electric plants is about 33.6 percent.) Until recently, the waste heat was discharged into surface waters near the plants, but significant ecological damage resulted. The United States Environmental Protection Agency (EPA), which sets air and water quality standards, now requires that all large nuclear and fossil electric powerplants have closed-cycle heat disposal systems (cooling towers) which disperse the heat to the atmosphere rather than the waterways. This requirement, however, adds significant costs to nuclear plant construction and reduces the efficiency of electric power generation.

The second waste product of nuclear power poses a much more formidable problem. Radioactive wastes are composed of fission product nuclei, radioactive nuclei formed when reactor component materials (stainless steel, water, etc.) absorb reactor neutrons, and actinide nuclei (such as thorium, uranium, plutonium), formed by the natural decay of uranium at mines and mills or from multiple neutron absorption by uranium nuclei in

Table 5. Fuel Flows in Typical BWR and PWR Reactors*

Reactor Type	Fuel in Core	Burn-up at Discharge	Core Fraction Annually Discharged	Loading Enrichment	Discharge Enrichment	Discharge Plutonium
	MTU	MWD/MTU		Percent U-235		Kg/MTU
BWR	150	28,000	0.24	2.6	0.8	8
PWR	85	31,000	0.34	3.0	0.9	10

*See Explanatory Note 3 and 4 for discussion of units.
Source: *Nuclear Industry Status,* Nuclear Assurance Corporation Quarterly Report.

the reactor fuel. The actinide wastes have such long half-lives[7] that their radiation hazard lingers for thousands of years. However, their radiation is not very penetrating and they must be ingested to do harm.

In November 1972, the National Academy of Sciences completed a study on the biological effects of radiation. Estimates were made of the average annual radiation exposures of the American populace and are given in Table 6. EPA estimates that the maximum average exposure due to future nuclear industry in the United States will be 1 millirem[8] per year, which is only 1 percent of natural background radiation. Current Nuclear Regulatory Commission standards for all effluents from LWR operations specify that no person at or beyond the site boundary at a power plant shall be exposured to an incremental dose of more than 10 millirems per year, which is 10 percent of the exposure due to natural background or 14 percent of the medical X-ray exposure shown in Table 6. The two harmful biological effects of exposure to these low radiation levels are cancer and birth defects due to genetic mutation. It should be mentioned that coal-burning also produces radioactive emissions due to radium and thorium impurities in coal. Actual measurements 1 to 2 miles downwind from a 1,000-megawatt coal plant range from 0.3 to 24 millirem per year.

Table 6. Estimates of Annual Whole-Body Radiation Dose Rates in the United States, 1970*

Source	Average Dose Rate	Percent of Total Dose
	Millirems per year	
Environmental		
Natural	102	56.1
Global Fallout	4	2.2
Nuclear Power	0.003	0.002
Subtotal	106	58.3
Medical		
Diagnostic	**72	39.6
Radiopharmaceuticals	1	0.6
Subtotal	73	40.2
Occupational	0.8	0.4
Miscellaneous	2	1.1
TOTAL	182	100.0

*For given segments of the population, dose rates considerably greater than these average values may be experienced.
**Based on the abdominal dose.
Source: *The Effects on Populations of Exposure to Low Levels of Ionizing Radiation* (National Academy of Sciences-National Research Council, November 1972).

Most of the radioactive wastes from nuclear power do not get released at the powerplant because they are trapped within the fuel rods. Ninety-nine percent of the radioactive waste is extracted from the spent fuel at the reprocessing plant. This concentrated "high-level" waste contains both fission products and actinides. A firm policy for disposition of the high-level waste has not been established. ERDA, which is responsible for policy in this area, at one time favored encapsulating the waste and disposing of it in geological formations such as bedded salt. However, public pressure and technological set-backs at the proposed Lyons, Kansas, disposal site have forced a reassessment of that policy. After considering the use of temporary facilities to hold the wastes for 20 to 30 years while other geological sites or alternative technologies could be investigated, ERDA recently returned to advocacy of bedded salt formations.

An estimate of the total health effects from a 1,000-megawatt nuclear plant are given in Table 7. These figues

[7]See Explanatory Note 1 for a discussion of half-life.

[8]The millirem is a unit of measure for the amount of biological damage produced by radiation.

Table 7. Health Effects of Civilian Nuclear Power

Activity	Fatalities per 1000 MWe Plant-year			Injuries
	Accidents (not radiation-related)	Radiation-related (cancers and genetic)	Total	Man-days lost
Uranium mining and milling	0.173	0.001	0.174	330.5
Fuel processing and reprocessing	0.048	0.040	0.099	5.6
Design and manufacture of reactors and instruments	0.040	NA	0.040	24.4
Reactor operation and maintenance	0.037	0.107	0.144	158
Waste disposal	NA	0.0003	0.0003	NA
Transport of nuclear fuel	0.036	0.010	0.046	NA
Totals	0.334	0.158	0.492	518

NA = Not available.
Source: P. Walsh, as quoted in D.J. Rose, "Nuclear Electric Power" *Science* (19 April 1974).

indicate that one fatality could be expected for every 2 years of operation of a nuclear plant. For comparison, operation of a coal-burning plant of the same size results in one death from mining accidents every 2 years. In addition, there are presently about 100 coal miners totally incapacitated due to black lung disease for each coal-burning plant in operation, although this number will probably decrease in the future because of more stringent safety standards in the mines. Fatalities due to sulfur emissions from coal burning could be as high as 40 to 100 per year by 1980 for each 1,000-megawatt plant in operation if there is no requirement for the removal of sulfur from the stack gases. With stringent sulfur removal requirements, the fatality rate becomes minuscule.

In conclusion, the nuclear power industry, still in its infancy, is beset by many problems, several of which are tied to financial woes of the electric utility industry, and others of which are basically related to public acceptance of the risks of nuclear power. In the nuclear section of the *Monthly Energy Review* we will monitor industry growth and price trends, capacity utilization, energy consumed in nuclear fuel processing, and import-export activity for nuclear fuels and services.

Part 1 Overview

For the first 2 months of 1975, production of energy in the United States was 1.4 percent below the same period last year. Crude oil exhibited the sharpest decline, down 5.0 percent, while natural gas production declined 2.6 percent. Together, these two fuels accounted for about 67.5 percent of the total output during January and February. Coal, which contributed 24.5 percent of domestic energy production, was the only major energy source that showed a production increase for these months, up 1.5 percent from 1974.

Imports of fossil fuels were 18.9 percent higher than in January and February 1974, when the Arab oil embargo was in effect. They were also 2.7 percent higher than during the same period in 1973. The largest increase was posted by crude oil, up 73.0 percent from last year. A pronounced 21.9-percent decline, however, was registered for refined petroleum product imports. In fact, product imports during February were at their lowest level since October 1971. Natural gas imports have also declined from their levels during the first 2 months of 1974, but only by 1.2 percent. Preliminary data indicate that during February the principal sources of crude oil imports were Nigeria, accounting for 22 percent of the total, and Canada, 13 percent, while about 82 percent of refined product imports came from Caribbean refineries.

During January 1975, the United States consumed 1.0 percent more energy than in January 1974, but 3.5 percent less than for the same month in 1973. Consumption of refined products, which accounted for 43.7 percent of total domestic energy consumption, showed a 1.8-percent gain over last year, while consumption of natural gas (accounting for 33.1 percent of the total) declined by an equal amount. Coal consumption (17.3 percent of the total) was down slightly by 0.3 percent. In contrast, nuclear power consumption increased a substantial 72.4 percent, while consumption of hydroelectric power was up 0.5 percent. These two energy sources, however, supplied only 5.9 percent of domestic energy demand during the month.

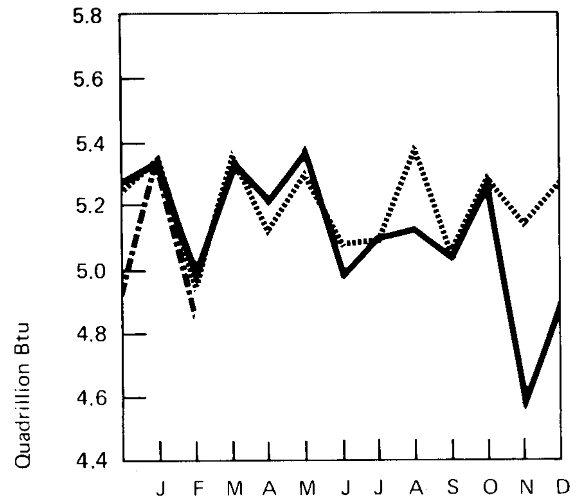
Stocks of distillate and residual fuel oil continued to exhibit normal seasonal drawdowns in February, declining 13.7 and 5.2 percent, respectively, from their levels at the end of January. On the other hand, crude oil inventories increased 4.3 percent in February, reaching their highest levels since May 1972. Motor gasoline stocks also increased seasonally during the month, closing 2.8 percent higher than their January levels, as they reached their highest levels since February 1972. Stocks of natural gas liquids at the end of 1974 were 15.1 percent above levels a year ago. Coal inventories at the end of January, however, were 4.6 percent below January 1974.

Production of electricity for the first 2 months of 1975 was 4 percent greater than for the corresponding period in 1974. As a consequence, consumption of coal and fuel oil at electric utilities was also higher. Utility plants consumed 2 percent more coal and 16 percent more oil to generate electricity in January 1975 than in January 1974. Curtailments of natural gas, however, resulted in an 8-percent decrease in utility consumption of that fuel. Total sales of electricity during 1974 declined 0.3 percent from 1973. Sales to commercial customers exhibited the largest decrease at 1.2 percent. In contrast, industrial sales were up 0.3 percent, while sales to residential customers were essentially unchanged. Utility fuel stocks remained favorable at the end of January, with coal inventories representing a 72-day supply and oil a 63-day supply.

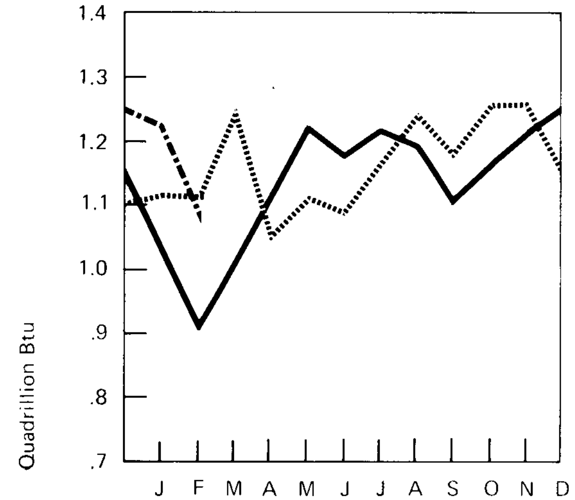
Following a 0.4-percent per gallon increase in January, the national average selling price of regular gasoline advanced only 0.1 cent per gallon in February. Retail gasoline prices are now 3.7 cents (7.6 percent) higher than a year ago and 15.7 cents (42.7 percent) higher than in February 1973. Average residential heating oil prices dropped for the second consecutive month in January to 36.2 cents per gallon. On the other hand, crude oil prices generally increased during the month. Although the cost of imported crude petroleum to the refiner decreased 19 cents per barrel in January, a 31-cent per barrel advance was posted in the refiner acquisition cost of domestic crude, resulting in a 28-cent per barrel increase in the composite cost of crude to the refiner.

Exploration activity for oil and gas in February remained well ahead of levels experienced last year. An average of 19 percent more rotary rigs were drilling for petroleum than in February 1974, and 7 percent more wells were completed during the month. The average number of seismic crews engaged in prospecting for oil and gas numbered 302, a net gain of 1 crew over the January count.

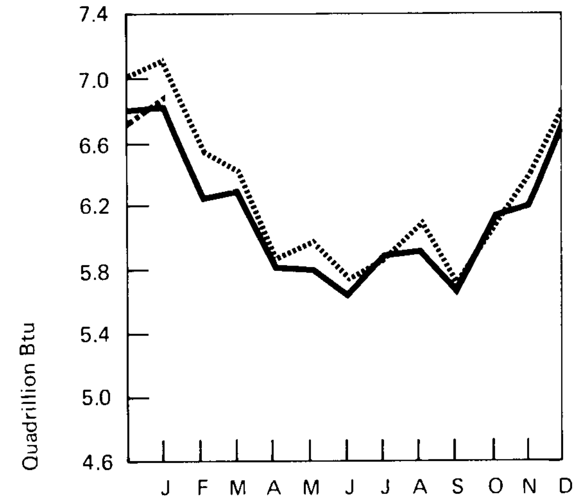
Domestic Production of Energy*



Imports of Fossil Fuels



Domestic Consumption of Energy**



*See Explanatory Note 6.
**See Explanatory Note 7.

1973
1974
1975

Part 2

Energy Sources

CRUDE OIL

After rising in January contrary to the normal seasonal pattern, crude oil production fell to 8,489,000 barrels per day in February, a level comparable to that of November and December 1974.

For the 3-month period ending February, crude oil production averaged 8,536,000 barrels per day, down slightly more than 500,000 barrels per day from the same period a year ago.

Imported crude oil receipts reported at refineries and terminals amounted to 4,061,000 barrels per day in February, up slightly from the previous month.

Crude oil stocks at refineries and major pipeline and marine terminals reached 264,833,000 barrels, the highest level since May 1972.

TOTAL REFINED PETROLEUM PRODUCTS

Domestic demand for total refined petroleum products for the period November 1974 through February 1975 averaged 17,425,000 barrels per day, 1.4 percent less than the same period last year.

Imports of refined products fell to 2,138,000 barrels per day, the lowest level since October 1971. Product imports during the month were 28 percent less than in February 1974 and 41 percent less than February 1973.

OIL HEATING DEGREE-DAYS

During February, the continental United States accumulated 5.6 percent less distillate oil heating degree-days than is normal for that month, reflecting higher than normal temperatures. This was the third consecutive month that total U.S. distillate oil degree-days were lower than normal.

Cumulative oil heating degree-days for the 1974-75 heating season continued to be higher than those of the previous heating season (by 3.0 percent), but were 5.4 percent below normal.

NATURAL GAS LIQUIDS

Production of natural gas liquids in 1974 totaled 616,098,000 barrels, a decline of 2.9 percent from the 1973 total of 634,423,000 barrels.

NATURAL GAS

Total marketed production during 1974 was 21,938 billion cubic feet, representing a decline of 3.2 percent from 1973 when 22,648 billion cubic feet were produced.

Imports fell from 1,033 billion cubic feet in 1973 to 959 billion cubic feet in 1974, a decline of 7.2 percent.

Domestic producer sales to major interstate pipelines were down 5.1 percent in 1974 compared with the previous year.

COAL

Production of bituminous coal and lignite in February 1975 was 49 million tons, virtually the same as in February 1974.

Exports for January 1975 were 15 percent below the average for the previous 12 months.

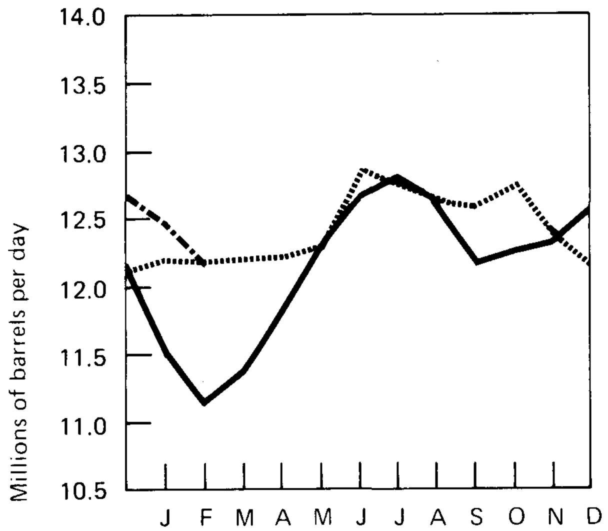
Revised consumption for the year 1974, at 551 million tons, was 5 million tons below 1973.

Crude Oil

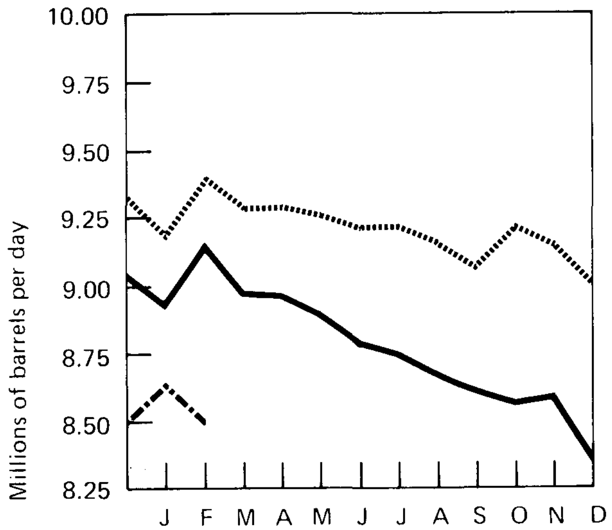
	Crude Input to Refineries		Domestic Production		Imports		Stocks*	
	In thousands of barrels per day						In thousands of barrels	
	BOM	FEA	BOM	FEA	BOM	FEA	BOM	FEA
1972 January	11,388		9,114		2,046		236,776	
February	11,356		9,336		2,081		238,882	
March	11,345		9,462		2,067		244,860	
April	11,184		9,513		2,004		253,492	
May	11,478		9,614		2,160		265,305	
June	11,841		9,522		2,085		257,601	
July	11,885		9,496		2,182		251,913	
August	11,915		9,483		2,112		244,333	
September	12,112		9,508		2,364		237,085	
October	11,871		9,482		2,516		239,949	
November	11,851		9,426		2,299		237,519	
December	12,113		9,335		2,667		232,803	
1973 January	12,190		9,179		2,732		224,056	
February	12,187		R9,395		2,873		221,893	
March	12,201		R9,272		3,162		230,696	
April	12,208		R9,292		3,049		235,383	
May	12,281		R9,262		3,215		244,777	
June	12,862		R9,214		3,220		235,846	
July	12,750		R9,217		3,501		230,750	
August	R12,635		R9,169		3,593		235,660	
September	12,560		R9,065		3,471		228,280	
October	12,758		R9,224		R3,739		233,520	
November	12,374		R1,161		3,452		237,001	
December	12,150		R9,063		2,891		229,504	
1974 January	11,491		8,907		2,382		220,261	
February	11,102		9,156		2,248		228,004	
March	11,355		8,950		2,462		231,705	
April	11,823		8,952		3,267		243,687	
May	12,333	12,777	8,903		3,908	3,748	256,726	252,270
June	12,697	12,709	8,777		3,925	3,957	255,762	253,008
July	12,811	12,905	8,754	8,698	4,091	4,167	255,936	252,399
August	12,644	12,731	8,682	8,717	3,924	3,852	251,905	247,040
September	12,124	12,253	8,621	8,622	3,797	3,758	253,623	249,476
October	12,286	12,430	8,568	8,651	3,810	3,936	256,430	255,003
November	12,332	12,402	8,596	8,458	3,958	3,997	258,123	256,271
December	12,519	12,671	8,352	8,471	3,869	3,979	252,158	248,808
1975 January		12,436		R8,644		3,964		R253,836
February		**12,144		**8,489		**4,061		**264,833

*See definitions.
**Preliminary data.
R=Revised data.
Sources: Bureau of Mines (BOM) and Federal Energy Administration (FEA) as indicated.

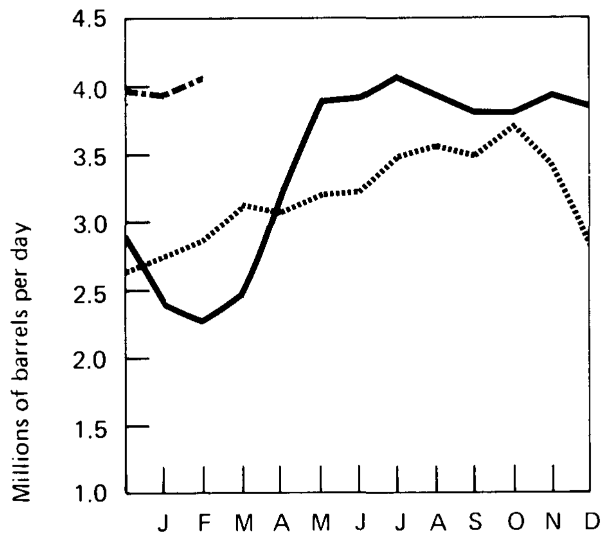
Crude Input to Refineries*



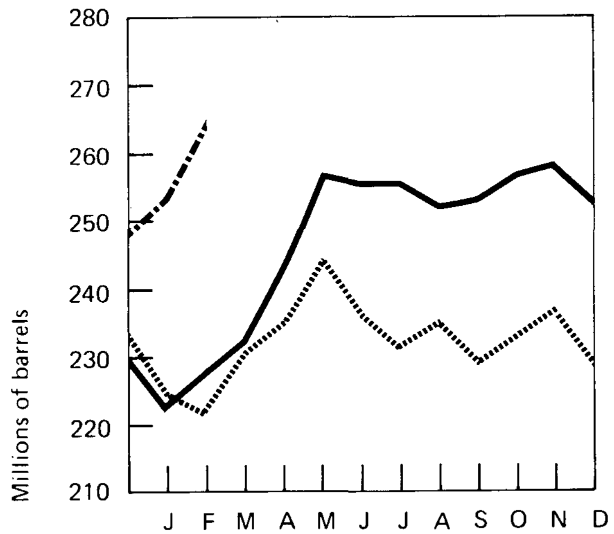
Domestic Production*



Imports*



Stocks*



1973
1974 BOM
1975 FEA

*See Explanatory Note 8.

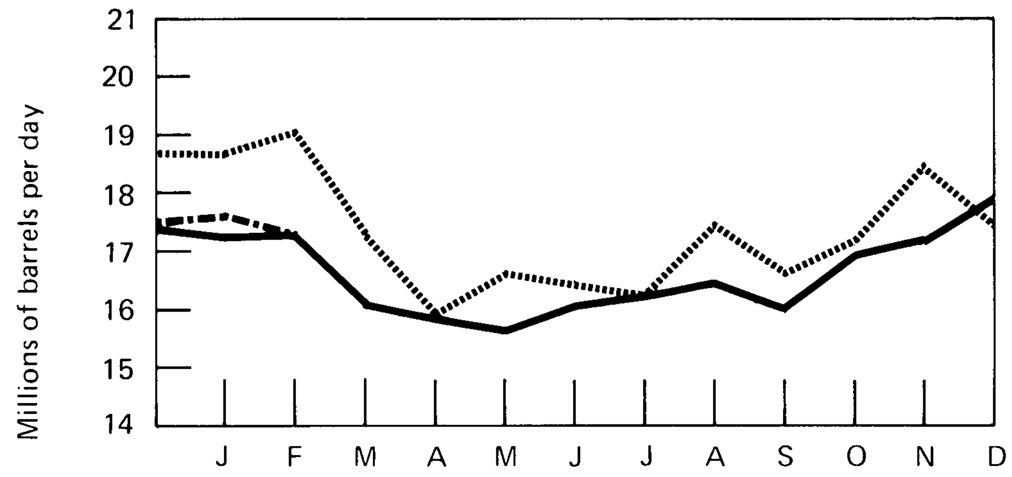
Total Refined Petroleum Products

In thousands of barrels per day

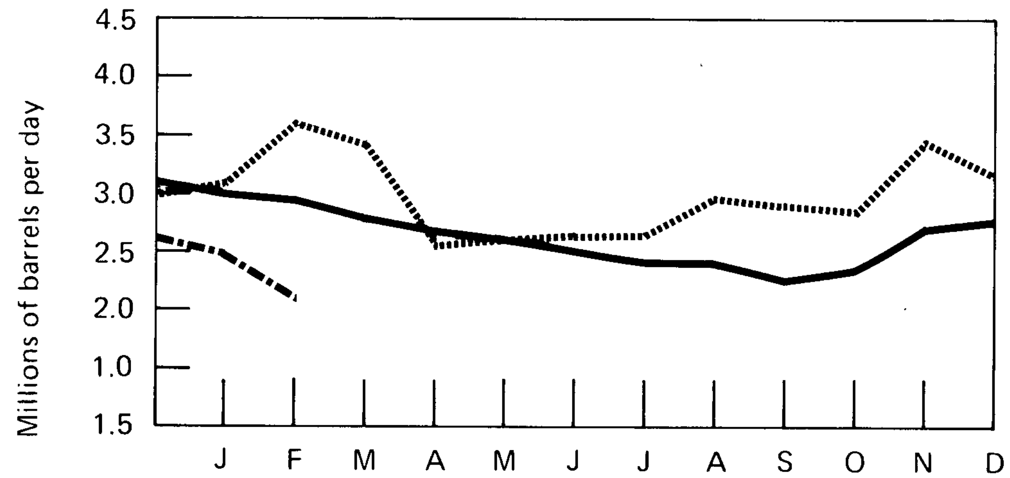
		Domestic Demand BOM	Domestic Demand FEA	Imports* BOM	Imports* FEA
1972	January	16,735		2,721	
	February	17,861		2,764	
	March	16,870		2,730	
	April	15,529		2,298	
	May	14,801		2,208	
	June	15,615		2,382	
	July	14,821		2,215	
	August	15,936		2,344	
	September	15,489		2,342	
	October	16,455		2,607	
	November	17,610		2,653	
	December	18,738		3,039	
1973	January	R18,713		R3,125	
	February	R19,094		R3,635	
	March	R17,216		R3,448	
	April	R15,921		R2,545	
	May	R16,626		R2,626	
	June	R16,481		R2,670	
	July	R16,372		R2,678	
	August	R17,499		R2,999	
	September	R16,656		R2,941	
	October	R17,202		R2,894	
	November	R18,492		R3,470	
	December	R17,538		R3,164	
1974	January	17,270		2,973	
	February	17,371		2,973	
	March	16,045		2,753	
	April	15,919		2,703	
	May	15,720	15,740	2,580	2,454
	June	16,176	16,191	2,493	2,218
	July	16,301	15,853	2,397	2,140
	August	16,546	15,803	2,434	2,281
	September	15,994	16,318	2,225	2,180
	October	17,025	17,121	2,340	2,361
	November	17,214	17,129	2,704	2,581
	December	17,997	17,588	2,781	2,638
1975	January		R17,581		2,486
	February		**17,295		**2,138

*See definitions. **Preliminary data. R=Revised data.
Sources: Bureau of Mines (BOM) and Federal Energy Administration (FEA) as indicated.

Domestic Demand*



Imports*



*See Explanatory Note 8.

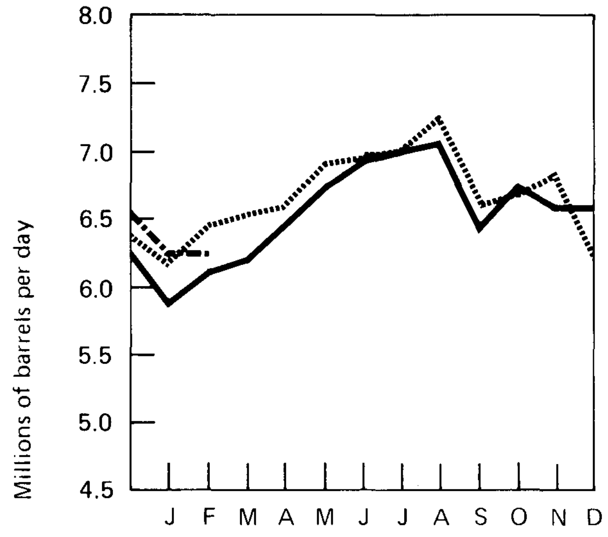
1973
1974 BOM
1975 FEA

Motor Gasoline

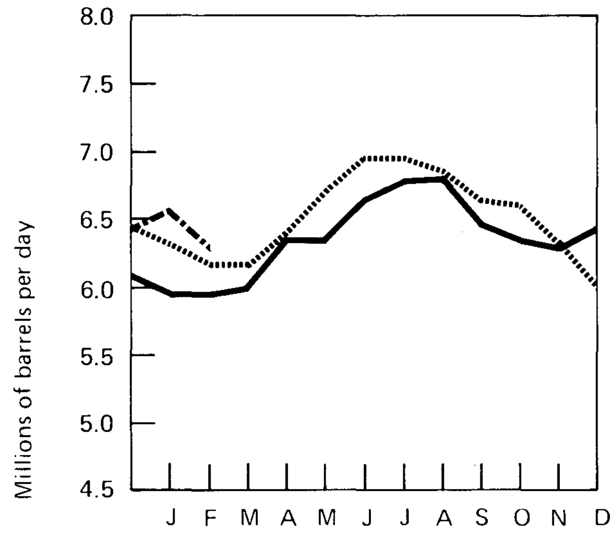
	Domestic Demand		Production*		Imports		Stocks*	
	In thousands of barrels per day						In thousands of barrels	
	BOM	FEA	BOM	FEA	BOM	FEA	BOM	FEA
1972 January	5,549		6,151		51		239,633	
February	5,710		5,989		66		249,927	
March	6,412		5,913		67		236,831	
April	6,283		5,833		52		225,153	
May	6,445		6,023		74		214,736	
June	6,822		6,244		75		200,143	
July	6,673		6,612		69		200,710	
August	6,938		6,588		81		192,706	
September	6,453		6,605		70		199,690	
October	6,350		6,532		71		207,776	
November	6,479		6,436		69		208,930	
December	6,378		6,424		69		212,770	
1973 January	6,118		6,341		59		221,823	
February	6,437		R6,855		95		216,367	
March	6,513		6,150		71		207,581	
April	6,541		6,377		63		204,708	
May	6,907		6,714		R101		202,081	
June	6,964		6,993		174		208,374	
July	7,023		6,986		133		211,488	
August	R7,257		6,880		R164		205,122	
September	6,581		R6,619		127		210,278	
October	6,677		6,621		194		214,525	
November	6,823		6,375		216		207,343	
December	R6,237		6,099		R202		209,395	
1974 January	5,804		5,900		163		217,463	
February	6,100		5,969		184		219,058	
March	6,162		5,982		225		220,307	
April	6,457		6,311		260		223,752	
May	6,745	6,406	6,328	6,301	250	228	218,670	229,878
June	6,919	6,895	6,663	6,642	211	145	217,381	226,652
July	6,959	6,941	6,792	6,835	212	122	218,838	227,195
August	7,061	6,849	6,815	6,776	253	192	218,951	231,015
September	6,388	6,652	6,453	6,485	202	140	227,031	230,181
October	6,712	6,542	6,336	6,340	171	175	220,748	229,275
November	6,547	6,659	6,292	6,257	174	264	218,385	225,226
December	6,558	6,551	6,419	6,451	141	170	218,346	227,363
1975 January		6,228		R6,574		203		244,425
February		**6,205		**6,279		**169		**251,189

*See definitions.
**Preliminary data.
R=Revised data.
Sources: Bureau of Mines (BOM) and Federal Energy Administration (FEA) as indicated.

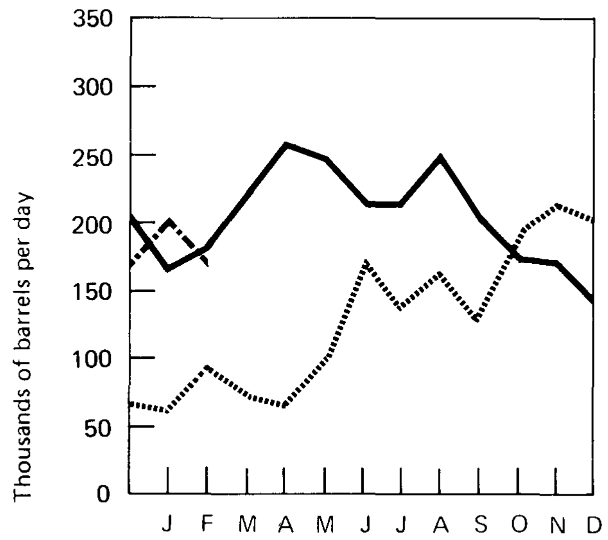
Domestic Demand*



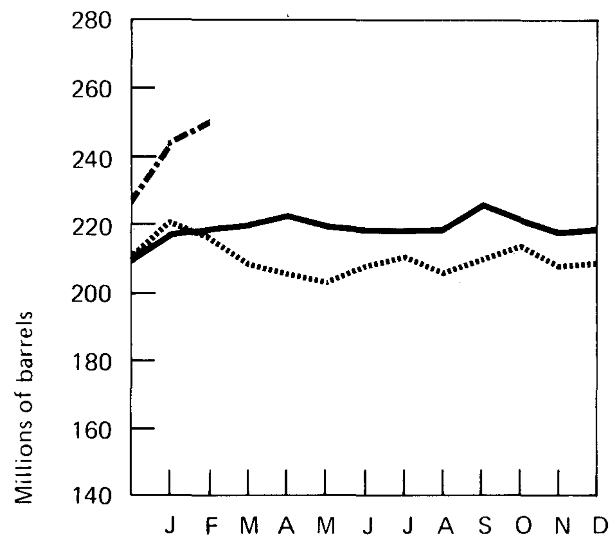
Production*



Imports*



Stocks*



*See Explanatory Note 8.

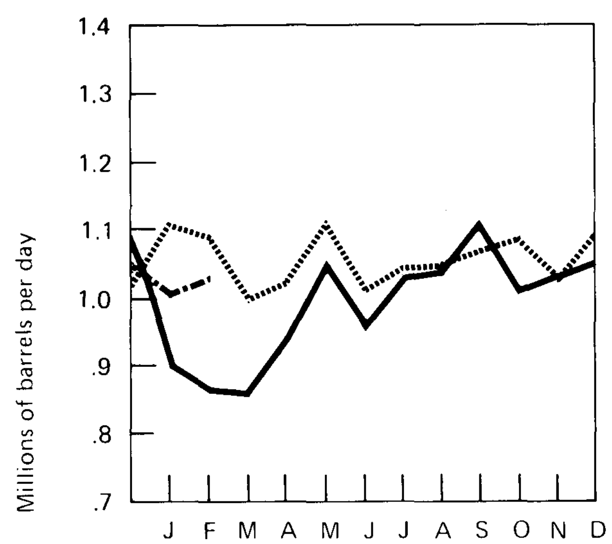
...... 1973
— 1974 BOM
·–· 1975 FEA

Jet Fuel

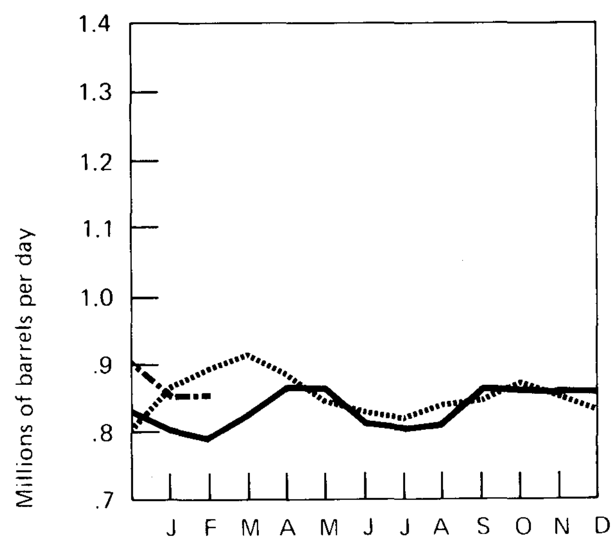
	Domestic Demand		Production		Imports		Stocks	
	In thousands of barrels per day						In thousands of barrels	
	BOM	FEA	BOM	FEA	BOM	FEA	BOM	FEA
1972 January	1,021		784		179		25,857	
February	1,141		900		220		25,230	
March	1,008		906		167		27,147	
April	986		877		124		27,568	
May	999		887		159		28,885	
June	1,163		859		292		28,356	
July	1,000		873		165		29,429	
August	946		837		181		31,649	
September	1,035		810		190		30,597	
October	1,171		822		286		28,633	
November	1,050		800		184		26,650	
December	1,030		811		189		25,493	
1973 January	1,110		864		231		24,814	
February	1,090		898		221		25,437	
March	R 994		917		152		27,585	
April	1,015		887		145		27,881	
May	R1,112		840		211		25,825	
June	1,007		836		R164		25,447	
July	R1,046		825		R232		25,661	
August	1,049		844		180		24,851	
September	R1,070		847		R235		25,149	
October	R1,104		875		R246		25,577	
November	R1,025		852		R275		28,539	
December	R1,087		830		R259		28,544	
1974 January	895		800		136		29,732	
February	860		783		75		29,617	
March	956		832		139		29,996	
April	941		868		132		31,725	
May	1,053	915	868	873	205	97	32,324	33,574
June	952	1,016	810	886	141	115	32,200	33,128
July	1,028	1,032	802	813	214	188	31,671	32,231
August	1,031	1,076	805	849	206	202	30,989	31,594
September	1,109	1,100	867	883	217	183	30,186	30,587
October	1,011	1,092	868	905	161	216	30,564	31,488
November	1,032	1,055	863	861	140	222	29,616	31,303
December	1,043	1,138	861	908	178	219	29,435	30,957
1975 January		1,001		847		R164		31,221
February		*1,031		*849		*166		*30,641

*Preliminary data.
R=Revised data.
Sources: Bureau of Mines (BOM) and Federal Energy Administration (FEA) as indicated.

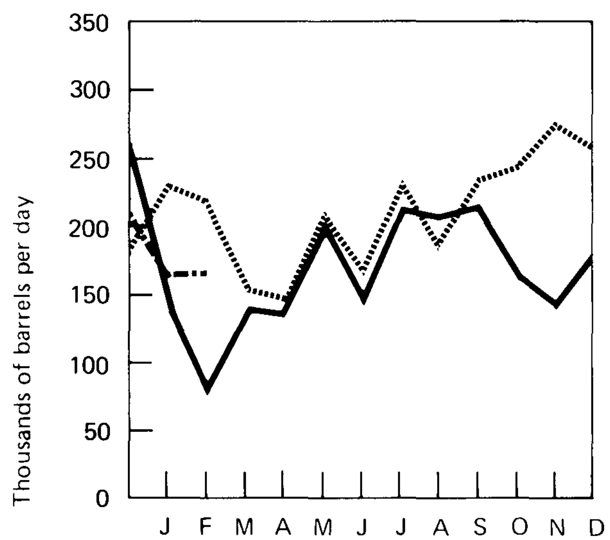
Domestic Demand*



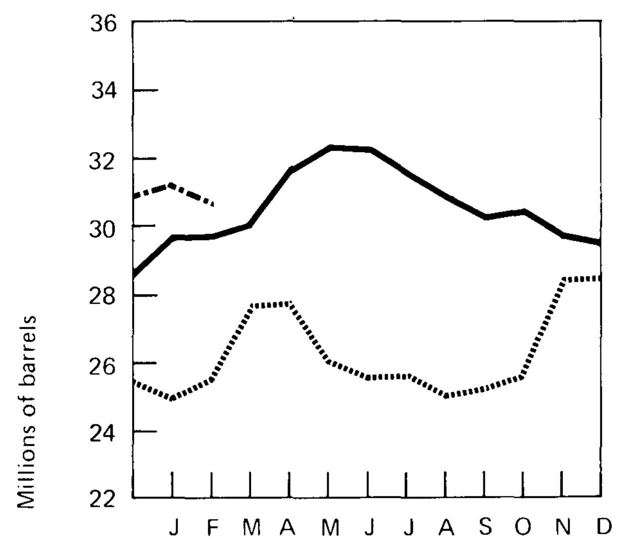
Production*



Imports*



Stocks*



1973
1974 BOM
1975 FEA

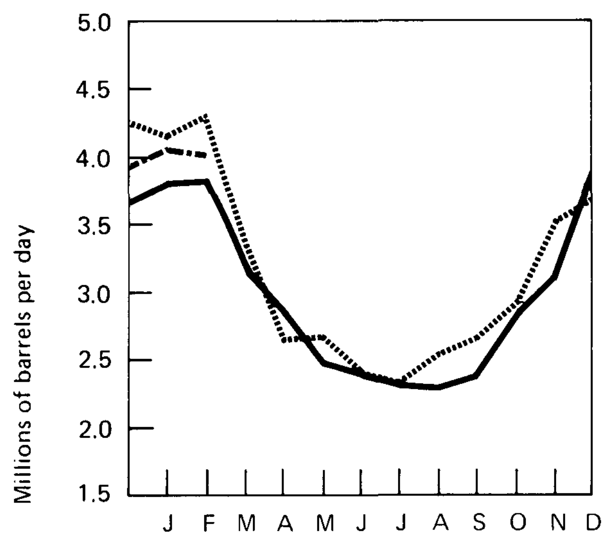
*See Explanatory Note 8.

Distillate Fuel Oil

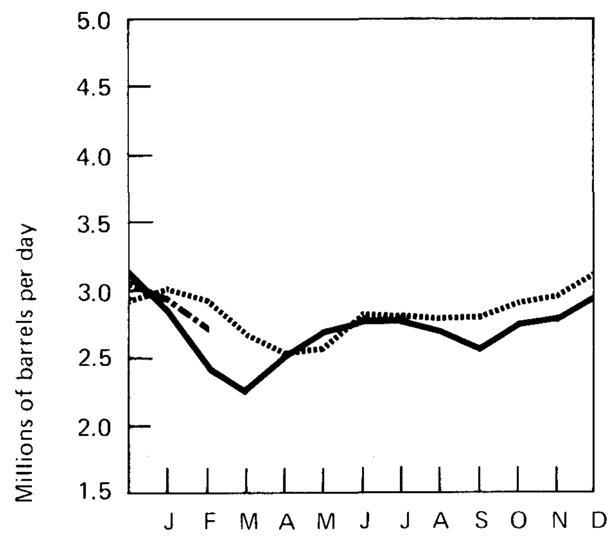
	Domestic Demand		Production*		Imports		Stocks*	
	In thousands of barrels per day						In thousands of barrels	
	BOM	FEA	BOM	FEA	BOM	FEA	BOM	FEA
1972 January	3,723		2,538		197		160,027	
February	4,164		2,653		204		122,154	
March	3,482		2,564		257		101,728	
April	2,778		2,476		189		98,288	
May	2,250		2,585		132		112,892	
June	2,194		2,623		96		128,739	
July	1,765		2,529		97		155,557	
August	2,064		2,582		92		174,674	
September	2,205		2,624		99		190,250	
October	2,759		2,722		203		195,530	
November	3,383		2,719		227		182,581	
December	4,232		2,938		382		154,284	
1973 January	R4,138		3,028		R364		130,958	
February	R4,302		2,937		R731		113,276	
March	R3,337		2,667		R602		111,270	
April	2,635		2,510		240		114,698	
May	R2,673		2,544		R268		119,104	
June	R2,419		2,825		R222		137,844	
July	R2,328		2,752		R318		160,869	
August	R2,555		2,801		R288		177,271	
September	R2,675		2,813		R313		190,171	
October	R2,930		2,911		R451		202,965	
November	3,508		2,922		R492		200,182	
December	R3,690		3,136		R439		196,421	
1974 January	3,820		2,880		449		181,179	
February	3,835		2,399		293		149,125	
March	3,145		2,226		267		128,822	
April	2,848		2,522		216		125,553	
May	2,453	2,616	2,704	2,741	271	288	141,806	151,345
June	2,386	2,249	2,783	2,818	228	175	160,645	173,639
July	2,302	2,251	2,792	2,881	214	168	182,458	198,374
August	2,295	2,271	2,704	2,779	111	112	198,673	217,632
September	2,377	2,473	2,551	2,655	144	143	208,269	227,069
October	2,863	2,816	2,770	2,787	213	264	209,908	234,257
November	3,145	3,058	2,801	2,883	443	403	212,875	241,125
December	3,855	3,923	2,924	3,028	517	466	200,029	227,877
1975 January		R4,055		2,954		R350		R204,576
February		**4,004		**2,708		**295		**176,530

*See definitions.
**Preliminary data.
R=Revised data.
Sources: Bureau of Mines (BOM) and Federal Energy Administration (FEA) as indicated.

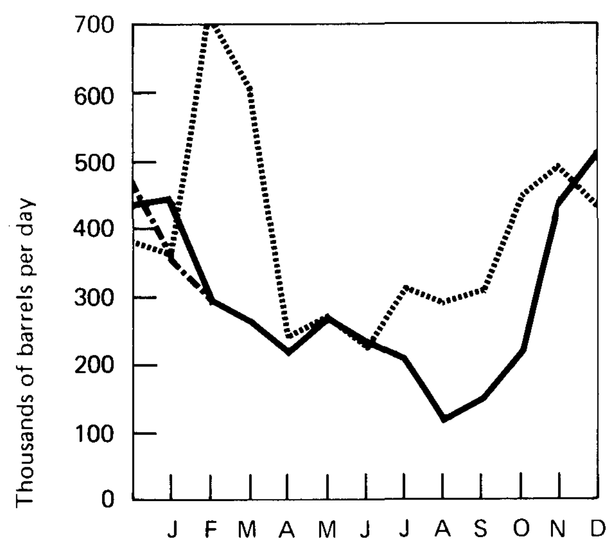
Domestic Demand*



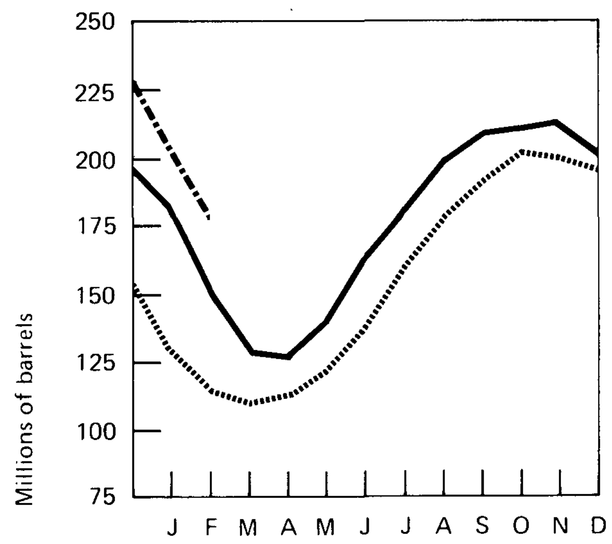
Production*



Imports*



Stocks*



*See Explanatory Note 8.

...... 1973
— 1974 BOM
-·- 1975 FEA

Oil Heating Degree - Days

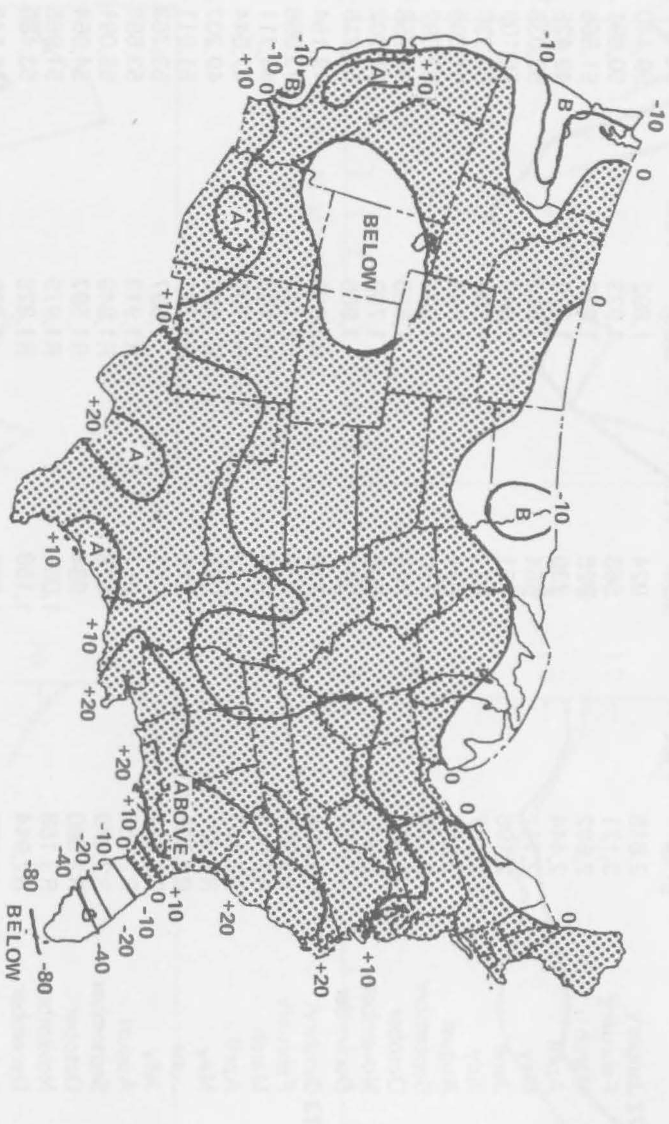
OIL HEATING DEGREE-DAYS*

Petroleum Administration for Defense (PAD) Districts	February (February 3 - March 2) 1975	1974**	Normal (1941-1970)**	Cumulative Since July 1, 1974 1974-75	1973-74**	Normal (1941-1970)**
PAD District I	747.6	822.5 (- 9.1)	821.9 (- 9.0)	3,313.0	3,218.2 (+ 2.9)	3,551.8 (- 6.7)
New England	964.5	1,018.8 (- 5.3)	1,023.1 (- 5.7)	4,283.7	4,167.1 (+ 2.8)	4,480.8 (- 4.4)
Conn., Maine, Mass., N.H., R.I., Vt.						
Middle Atlantic	856.2	948.7 (- 9.8)	933.5 (- 8.3)	3,744.3	3,703.1 (+ 1.1)	4,013.8 (- 6.7)
Del., Md., N.J., N.Y., Pa.						
Lower Atlantic	327.2	384.5 (-14.9)	409.6 (-20.1)	1,544.7	1,359.4 (+13.6)	1,758.4 (-12.2)
Fla., Ga., N.C., S.C., Va., W. Va.						
PAD District II	1,077.2	1,031.6 (+ 4.4)	1,061.9 (+ 1.4)	4,738.9	4,578.1 (+ 3.5)	4,831.9 (- 1.9)
Ill., Ind., Iowa, Kans., Ky., Mich., Minn., Mo., Nebr., N. Dak., Ohio, Okla., S. Dak., Tenn., Wis.						
PAD District III	394.2	374.1 (+ 5.4)	420.3 (- 6.2)	1,741.4	1,583.3 (+10.0)	1,906.9 (- 8.7)
Ala., Ark., La., Miss., N. Mex., Tex.						
PAD District IV	947.3	851.6 (+11.2)	921.5 (+ 2.8)	4,617.6	4,594.5 (+ 0.5)	4,754.2 (- 2.9)
Colo., Idaho, Mont., Utah, Wyo.						
PAD District V	570.4	535.6 (+ 6.5)	557.4 (+ 2.3)	2,816.7	2,885.8 (- 2.4)	3,055.5 (- 7.8)
Ariz., Calif., Nev., Oreg., Wash.						
U.S. Total	801.9	839.3 (- 4.4)	849.2 (- 5.6)	3,563.6	3,459.8 (+ 3.0)	3,765.8 (- 5.4)

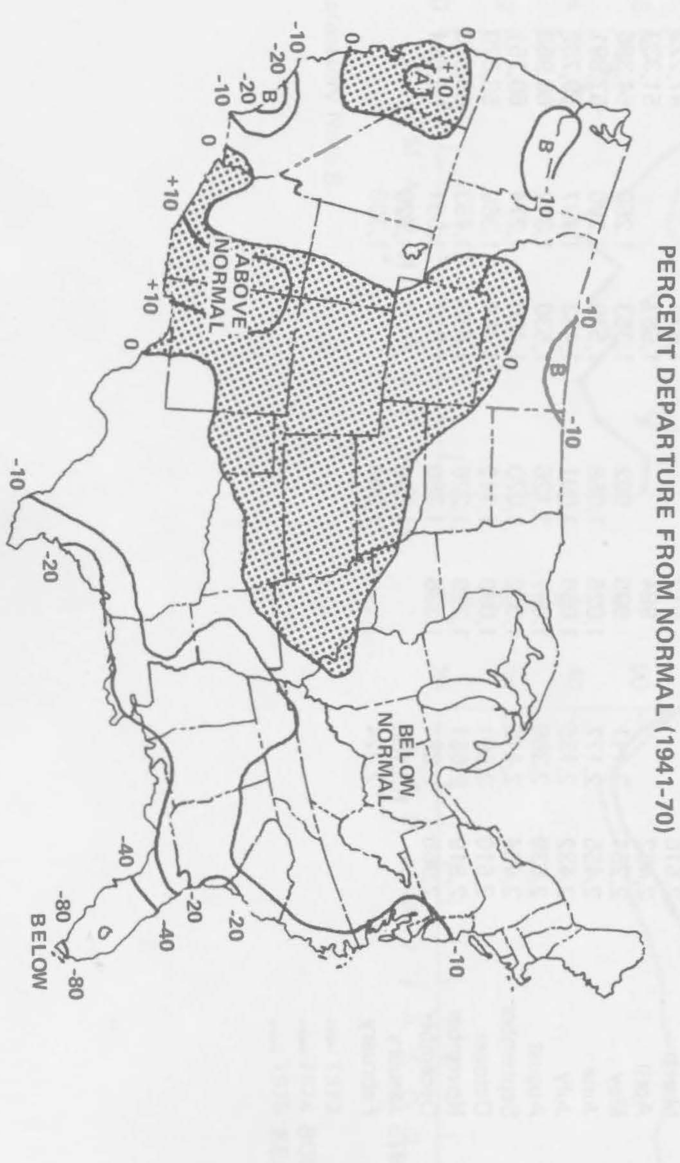
*See Explanatory Note 9 for explanation of oil heating degree-days.
**Percentage change in parenthesis.

HEATING DEGREE-DAYS ACCUMULATED FROM JULY 1, 1974 MARCH 2, 1975

PERCENT DEPARTURE FROM 1973-74



PERCENT DEPARTURE FROM NORMAL (1941-70)



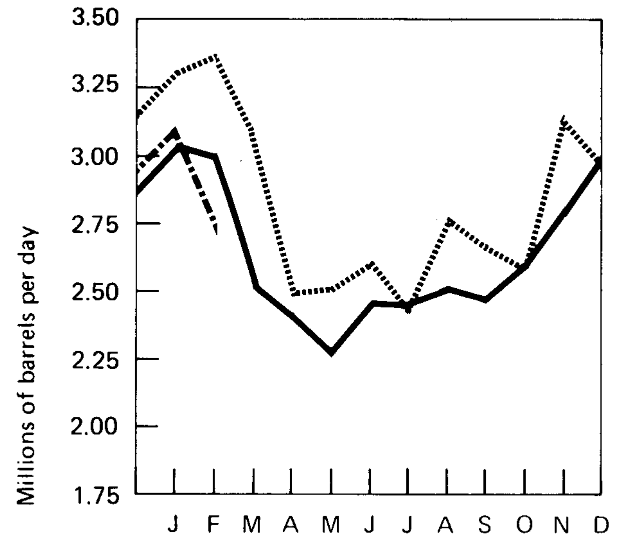
NOTE: Above normal heating degree-days correspond to below normal temperatures.
Source: Department of Commerce – NOAA.
Based on preliminary telegraphic reports.

Residual Fuel Oil

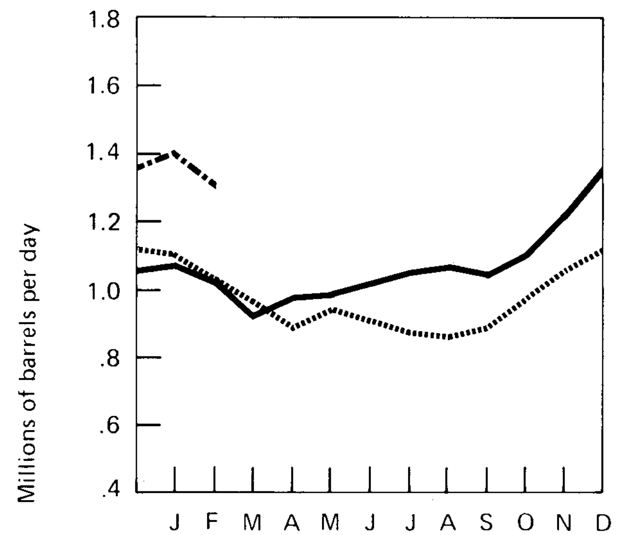
	Domestic Demand		Production		Imports		Stocks In thousands of barrels	
	In thousands of barrels per day							
	BOM	FEA	BOM	FEA	BOM	FEA	BOM	FEA
1972 January	2,815		924		1,892		59,440	
February	3,171		963		1,923		50,891	
March	2,682		828		1,926		51,566	
April	2,444		739		1,676		49,425	
May	2,111		664		1,573		53,035	
June	2,196		661		1,649		56,109	
July	2,107		673		1,594		60,230	
August	2,257		674		1,653		61,399	
September	2,239		710		1,625		63,692	
October	2,362		745		1,655		63,758	
November	2,843		890		1,769		57,702	
December	3,151		1,124		1,968		55,216	
1973 January	R3,306		1,112		R2,019		49,154	
February	R3,382		1,038		R2,147		43,058	
March	R3,084		955		R2,196		44,711	
April	R2,477		877		R1,705		47,044	
May	R2,521		948		R1,668		49,207	
June	R2,607		915		R1,761		51,811	
July	R2,412		882		1,597		53,363	
August	R2,755		851		R1,913		53,586	
September	R2,676		878		R1,849		55,091	
October	R2,590		984		R1,597		54,964	
November	R3,158		1,061		R1,979		51,985	
December	R2,944		1,158		R1,826		53,480	
1974 January	3,035		1,072		1,732		46,548	
February	3,010		1,029		1,923		45,004	
March	2,516		912		1,674		47,222	
April	2,432		984		1,587		51,339	
May	2,251	2,111	995	992	1,353	1,250	54,356	64,548
June	2,455	2,177	1,026	1,058	1,549	1,260	57,891	68,646
July	2,432	2,135	1,056	1,091	1,433	1,197	59,787	73,066
August	2,539	2,368	1,067	1,126	1,530	1,342	60,988	76,011
September	2,454	2,419	1,032	1,070	1,400	1,274	60,251	72,723
October	2,610	2,501	1,099	1,112	1,464	1,369	58,679	72,090
November	2,819	2,631	1,229	1,226	1,636	1,453	60,363	73,581
December	2,965	2,881	1,335	1,350	1,612	1,561	59,694	74,521
1975 January		R3,103		R1,399		R1,529		68,628
February		*2,724		*1,304		*1,308		*65,076

*Preliminary data.
R = Revised data.
Sources: Bureau of Mines (BOM) and Federal Energy Administration (FEA) as indicated.

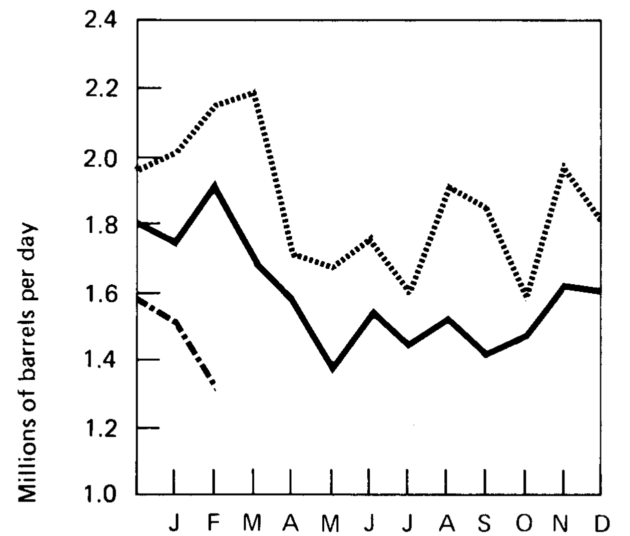
Domestic Demand*



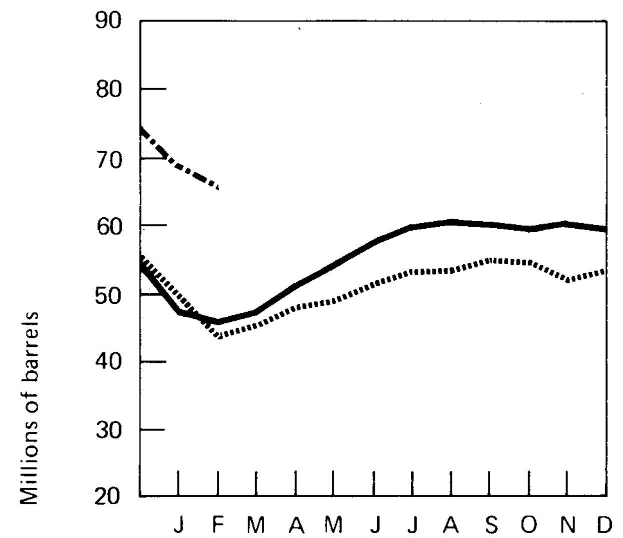
Production*



Imports*



Stocks*



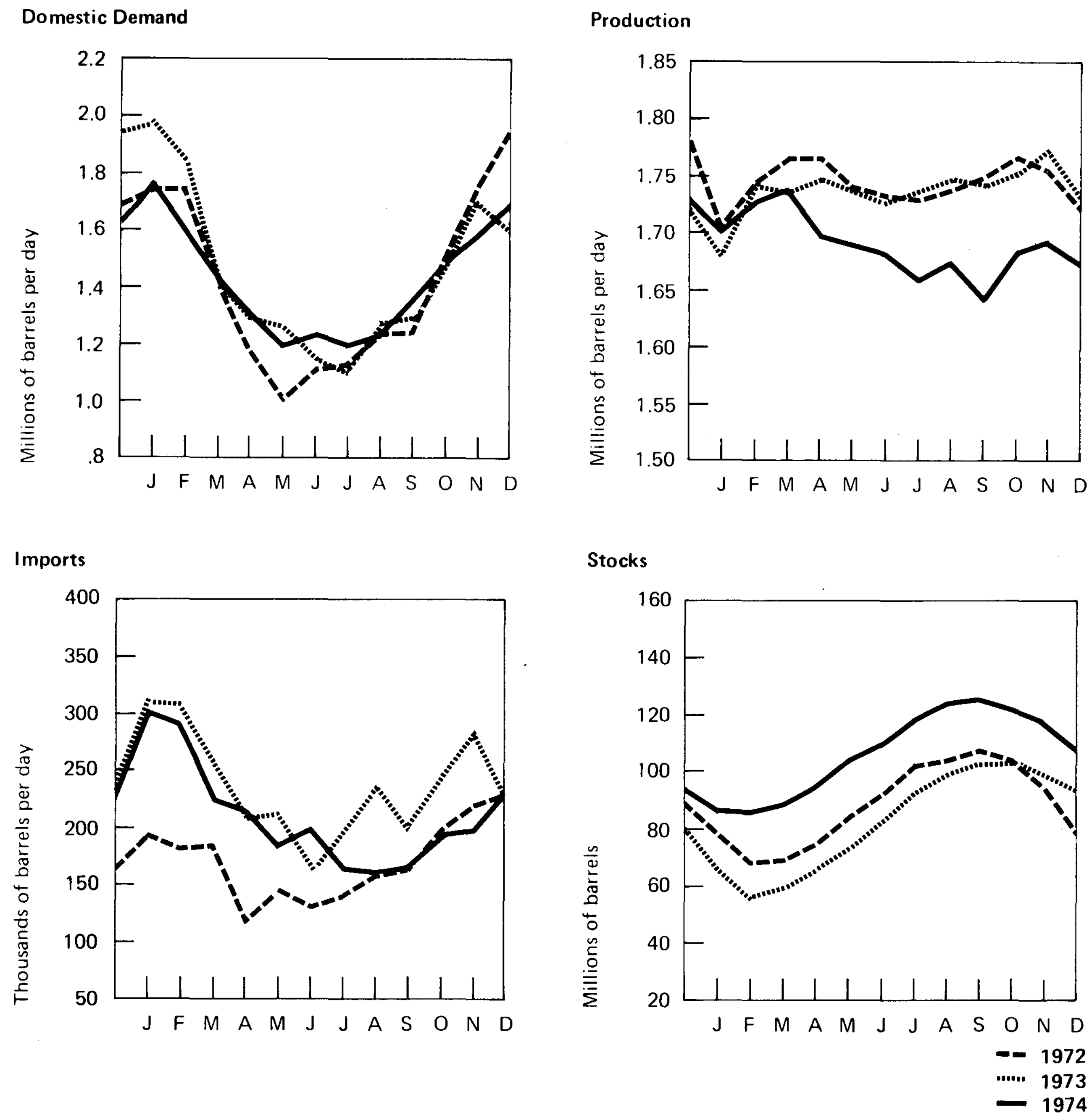
*See Explanatory Note 8.

...... 1973
— 1974 BOM
-·-· 1975 FEA

Natural Gas Liquids

		Domestic Demand*	Production*	Imports	Stocks*
		In thousands of barrels per day			In thousands of barrels
1972	January	1,746	1,705	196	76,704
	February	1,752	1,747	182	68,232
	March	1,417	1,768	186	68,777
	April	1,181	1,769	118	75,101
	May	995	1,737	147	84,984
	June	1,114	1,734	134	92,831
	July	1,121	1,731	141	100,363
	August	1,243	1,739	164	104,397
	September	1,244	1,751	168	108,853
	October	1,525	1,769	202	105,098
	November	1,768	1,757	221	94,673
	December	1,946	1,721	231	79,238
1973	January	1,994	1,680	313	64,343
	February	1,857	1,745	312	55,997
	March	R1,407	1,734	R260	58,471
	April	R1,299	R1,750	R201	65,297
	May	R1,270	1,739	R216	73,942
	June	1,149	1,727	163	83,057
	July	R1,109	1,737	R199	93,362
	August	R1,281	1,748	R239	98,996
	September	R1,297	1,741	R206	103,907
	October	R1,499	1,756	R249	104,215
	November	R1,703	1,774	R286	98,320
	December	R1,607	1,729	R231	94,106
1974	January	1,779	1,699	305	85,820
	February	1,593	1,728	294	84,734
	March	1,408	1,741	224	89,362
	April	1,321	1,696	215	95,707
	May	1,181	1,689	182	104,739
	June	1,242	1,684	200	111,356
	July	1,187	1,657	163	118,804
	August	1,221	1,676	163	125,120
	September	1,359	1,638	167	126,454
	October	1,493	1,686	200	123,634
	November	1,596	1,694	199	118,026
	December	1,692	1,670	230	108,377
1975	January		**1,629		

*See Explanatory Note 10.
**Preliminary data.
Source: Bureau of Mines.

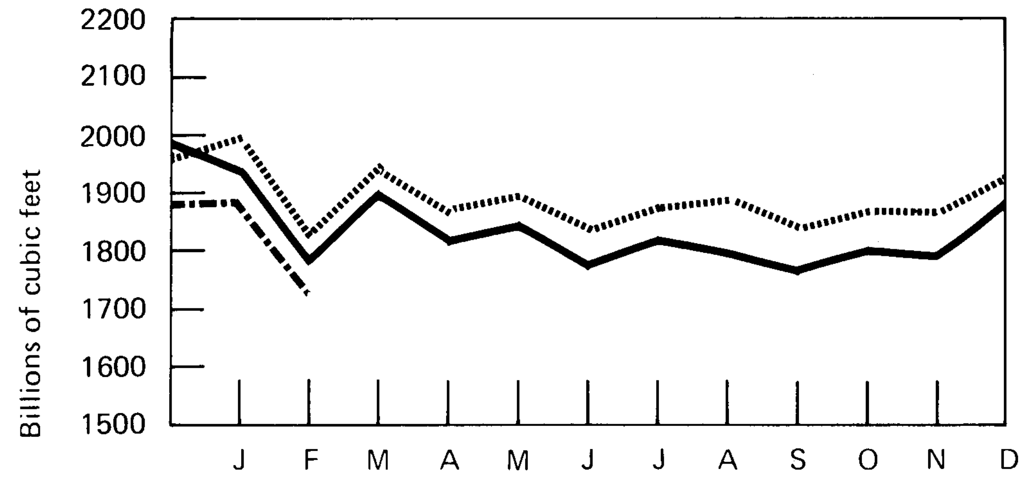


Natural Gas

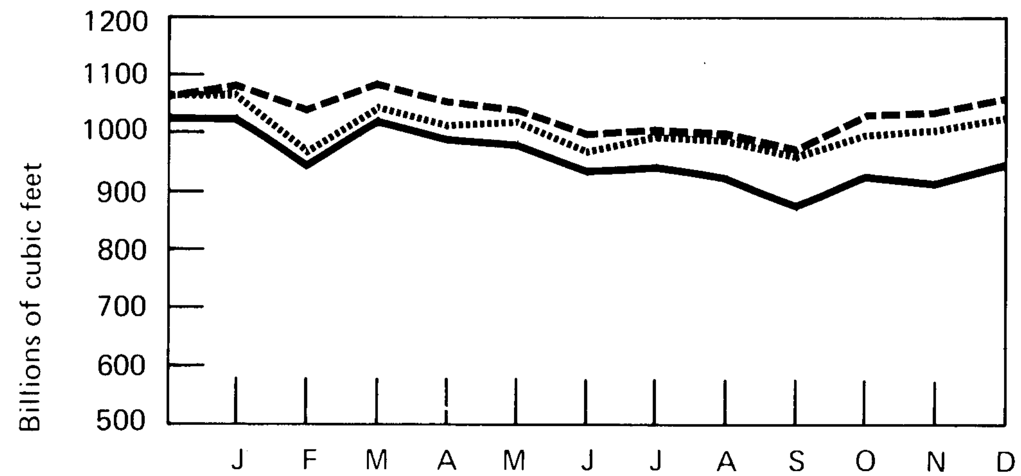
		Marketed Production	Domestic Producer Sales to Major Interstate Pipelines	Imports
			In billion cubic feet	
1972	January	1,994	1,086	117
	February	1,902	1,035	112
	March	1,937	1,091	88
	April	1,893	1,050	134
	May	1,867	1,045	111
	June	1,797	985	108
	July	1,837	1,013	102
	August	1,859	1,007	97
	September	1,854	970	114
	October	1,889	1,040	103
	November	1,896	1,041	111
	December	1,961	1,065	111
1973	January	1,994	1,069	93
	February	1,821	963	84
	March	1,952	1,052	91
	April	1,864	1,007	88
	May	1,898	1,026	86
	June	1,839	963	79
	July	1,880	999	80
	August	1,896	994	85
	September	1,840	956	82
	October	1,875	1,001	91
	November	1,863	1,000	85
	December	1,926	R1,038	89
1974	January	1,944	1,033	86
	February	1,773	941	79
	March	1,907	1,027	85
	April	1,812	987	83
	May	1,853	981	80
	June	1,777	928	74
	July	1,827	947	74
	August	1,797	932	76
	September	1,761	871	70
	October	R1,808	936	83
	November	*1,799	921	82
	December	**1,880	959	R87
1975	January	**1,890		**85
	February	**1,730		**78

*Preliminary data.
**Projected data.
R=Revised data.
Sources: Marketed Production and Imports—Bureau of Mines. Domestic Producer Sales—Federal Power Commission.

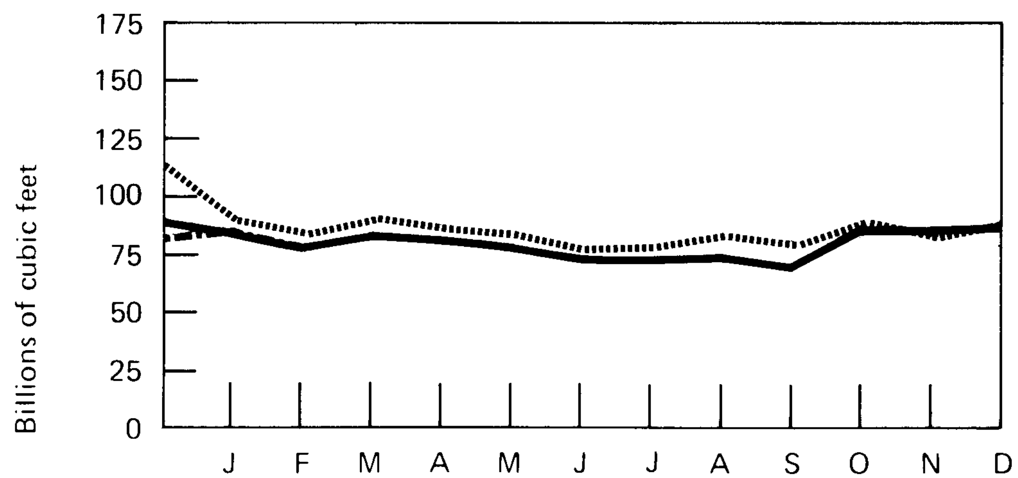
Marketed Production



Domestic Producer Sales to Major Interstate Pipelines



Imports



1972
1973
1974
1975

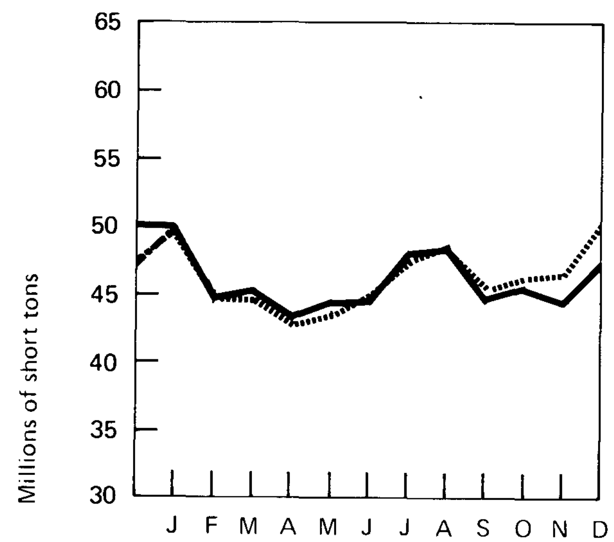
Coal

Bituminous and Lignite

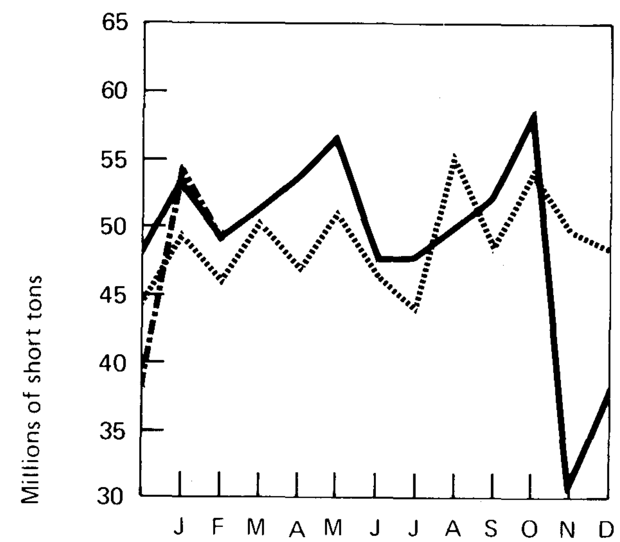
		Domestic Consumption*	Production**	Exports	Stocks
		In thousands of short tons			
1972	January	43,951	49,680	3,660	91,178
	February	43,178	49,112	3,630	92,183
	March	43,773	54,438	4,624	96,795
	April	40,158	49,814	4,915	102,981
	May	40,588	52,879	5,416	110,577
	June	40,505	50,083	4,882	115,723
	July	43,071	40,964	3,627	111,353
	August	44,698	52,169	6,337	114,665
	September	42,002	49,374	4,923	116,196
	October	43,050	51,671	5,210	120,135
	November	44,104	50,297	5,380	121,401
	December	47,698	44,904	3,392	117,442
1973	January	49,838	49,379	2,954	111,120
	February	44,652	45,893	2,669	108,870
	March	44,814	50,547	3,377	111,490
	April	42,689	46,999	5,063	112,585
	May	43,628	51,420	5,140	116,890
	June	45,115	46,613	4,969	109,960
	July	47,715	43,801	4,188	107,390
	August	48,840	55,874	5,133	106,910
	September	45,471	48,338	3,424	106,230
	October	46,427	54,382	5,882	107,490
	November	46,703	49,826	5,214	107,169
	December	50,130	48,666	4,889	R103,022
1974	January	R50,115	53,470	2,813	R 99,230
	February	R44,572	49,010	4,627	R 96,870
	March	R45,408	51,455	3,179	R 99,810
	April	R43,162	53,820	4,944	R106,490
	May	R44,612	57,135	6,032	R110,190
	June	R44,857	47,635	6,369	R112,030
	July	R48,187	47,855	5,307	R106,491
	August	R48,413	50,285	5,088	105,810
	September	R44,136	52,460	4,893	109,205
	October	R45,776	58,705	7,342	116,514
	November	44,589	30,865	6,744	108,710
	December	47,436	38,290	2,587	95,572
1975	January	49,940	54,885	4,254	94,696
	February		***49,035		

*See Explanatory Note 11.
**See Explanatory Note 12.
***Preliminary data.
R = Revised data.
Source: Bureau of Mines.

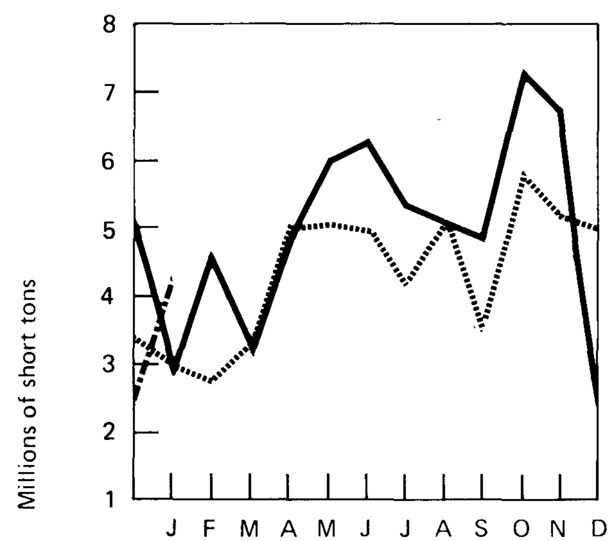
Domestic Consumption



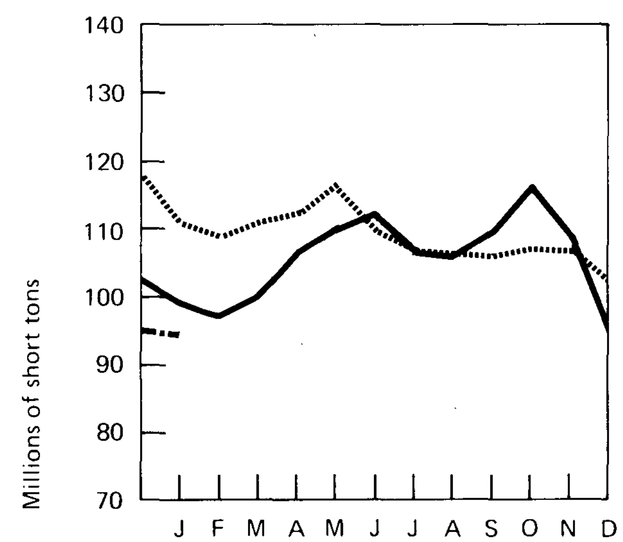
Production



Exports



Stocks



1973
1974
1975

ELECTRIC UTILITIES

Utility production of electricity for the first 2 months of 1975 was 4.2 and 1.2 percent greater than the corresponding periods in 1974 and 1973, respectively.

Nuclear power and hydroelectric power continued to increase their shares of total electricity production, growing from 22.5 percent in December to 23.4 percent in January.

Natural gas consumption by electric utilities continued to decline; January 1975 usage was down 1.2 percent from December 1974 and 7.8 percent compared with January 1974.

Coal and oil consumption by electric utilities in January was essentially unchanged from the previous month; compared with January 1974, however, oil consumption was up by 15.9 percent.

Coal and oil stockpiles at powerplants in January were about the same as in December, representing a 72-day supply for coal and a 63-day supply for oil.

Kilowatt-hour sales to residential and commercial customers in December 1974 were up 17.8 and 2.5 percent, respectively, over the previous month.

Kilowatt-hour sales to industry during December were down 6.1 percent from the previous month.

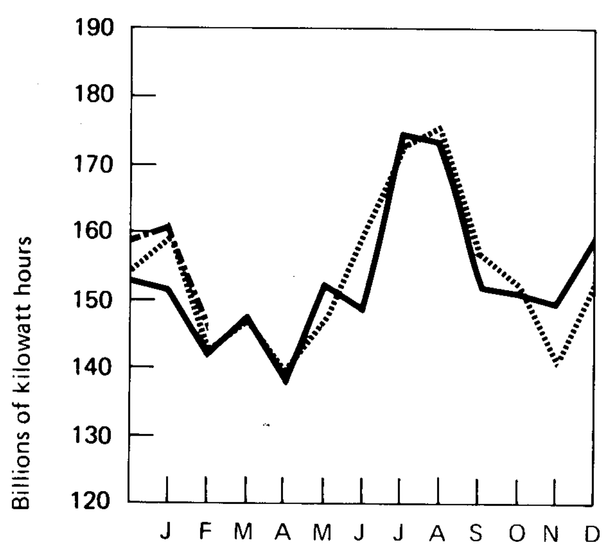
Part 3

Electric Utilities

Electric Utilities

		Total Production In millions of kilowatt hours	Percentage Produced from Each Source: Coal	Oil	Gas	Nuclear	Hydro-electric	Other*
1972	January	144,575	45.4	17.9	16.6	2.9	16.9	0.3
	February	137,301	45.7	17.3	18.0	2.6	16.1	0.3
	March	140,056	44.3	15.2	20.0	3.0	17.2	0.3
	April	132,138	43.6	13.4	22.3	2.7	17.7	0.3
	May	137,745	43.3	12.7	24.0	2.1	17.6	0.3
	June	145,523	42.3	13.3	25.5	2.6	15.9	0.4
	July	157,846	42.1	14.1	25.7	2.9	14.9	0.3
	August	162,822	42.8	13.7	25.7	3.5	13.9	0.4
	September	147,358	43.4	14.7	25.5	3.2	12.9	0.3
	October	143,742	44.3	14.1	25.2	3.2	13.0	0.2
	November	143,867	45.7	18.3	17.2	3.7	14.8	0.3
	December	154,350	45.9	19.5	14.4	3.9	16.0	0.3
1973	January	159,320	47.2	19.3	13.1	3.9	15.8	0.7
	February	143,109	47.4	18.1	14.0	4.1	16.0	0.4
	March	147,754	45.6	16.2	16.2	4.5	17.2	0.3
	April	139,273	46.0	14.4	17.9	4.2	17.2	0.3
	May	147,021	44.2	14.6	20.2	3.8	16.8	0.4
	June	160,962	43.5	16.0	21.6	4.2	14.5	0.2
	July	172,539	44.1	16.5	22.5	4.0	12.7	0.2
	August	175,928	44.5	17.2	21.6	4.4	11.9	0.4
	September	156,304	45.6	17.2	21.0	4.9	11.0	0.3
	October	153,888	45.6	17.6	19.8	4.8	11.8	0.4
	November	140,785	47.3	16.6	16.5	5.7	13.5	0.4
	December	153,276	47.9	16.3	13.2	5.1	17.1	0.4
1974	January	152,226	48.2	17.1	13.5	4.9	15.9	0.4
	February	141,723	46.7	15.7	13.3	5.5	18.4	0.4
	March	148,046	45.3	14.7	15.6	5.5	18.5	0.4
	April	137,586	45.0	14.1	17.4	4.3	19.0	0.2
	May	153,076	44.3	14.7	18.4	4.0	18.3	0.3
	June	148,119	44.6	14.6	20.0	4.1	16.5	0.2
	July	175,057	43.0	15.4	21.1	5.5	14.6	0.4
	August	174,021	43.0	15.6	20.3	7.3	13.4	0.4
	September	151,963	43.5	16.1	19.1	7.1	14.0	0.2
	October	151,768	44.0	16.6	18.4	7.0	13.8	0.2
	November	149,504	45.0	18.4	15.2	7.1	14.2	0.1
	December	158,867	45.7	19.3	12.4	8.0	14.5	0.1
1975	January	R160,512	45.2	19.1	12.2	8.2	15.2	0.1
	February	145,692						

Total Production



...... 1973
— 1974
-·- 1975

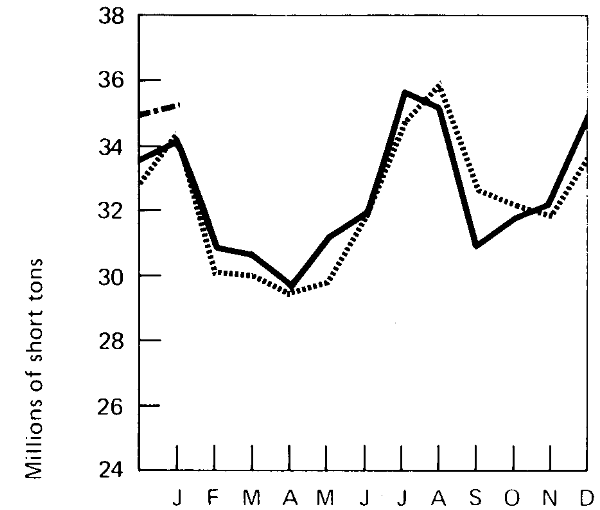
*Includes electricity produced from geothermal power, wood, and waste. R = Revised data.
Sources: Federal Power Commission.
Production data for latest month are from Edison Electric Institute.

Fuel Consumption

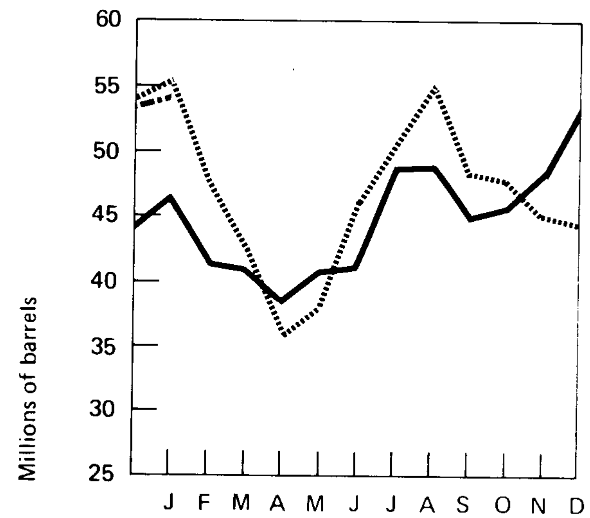
		Coal In thousands of short tons	Oil In thousands of barrels	Gas In millions of cubic feet
1972	January	30,231	46,555	251,029
	February	28,946	43,325	258,859
	March	28,472	38,809	294,804
	April	26,093	32,325	312,229
	May	26,823	32,106	351,543
	June	27,749	35,098	394,585
	July	30,214	40,646	433,533
	August	31,651	41,073	448,594
	September	28,988	38,723	398,799
	October	29,133	42,876	337,567
	November	29,926	47,914	262,447
	December	32,817	54,479	234,683
1973	January	34,591	55,773	219,270
	February	30,921	46,978	212,983
	March	30,746	42,701	255,314
	April	29,209	35,845	267,151
	May	29,683	38,097	316,989
	June	31,953	46,669	363,239
	July	34,833	50,956	414,408
	August	36,065	55,166	482,053
	September	32,723	47,937	418,776
	October	32,398	48,033	327,010
	November	31,856	45,158	247,038
	December	33,704	44,696	217,049
1974	January	34,468	46,700	222,080
	February	30,062	41,186	185,468
	March	31,135	40,007	244,288
	April	29,452	38,124	238,272
	May	31,341	41,046	304,166
	June	31,892	41,084	341,067
	July	35,809	48,909	399,259
	August	35,365	49,084	380,979
	September	30,965	44,791	320,978
	October	31,968	45,767	300,317
	November	32,208	48,542	240,471
	December	35,009	53,635	207,113
1975	January	35,238	54,144	204,688

Source: Federal Power Commission.

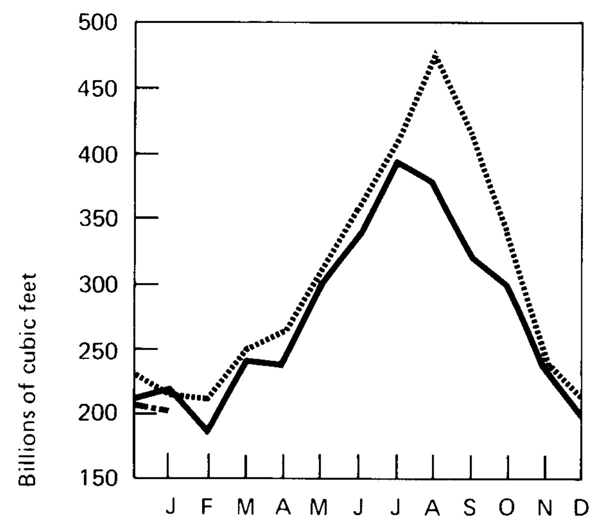
Coal Consumption



Oil Consumption



Gas Consumption



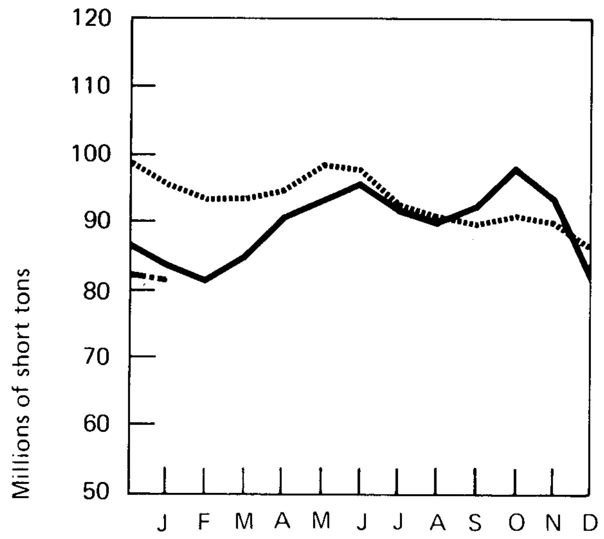
...... 1973
— 1974
-·- 1975

Stocks at End of Month

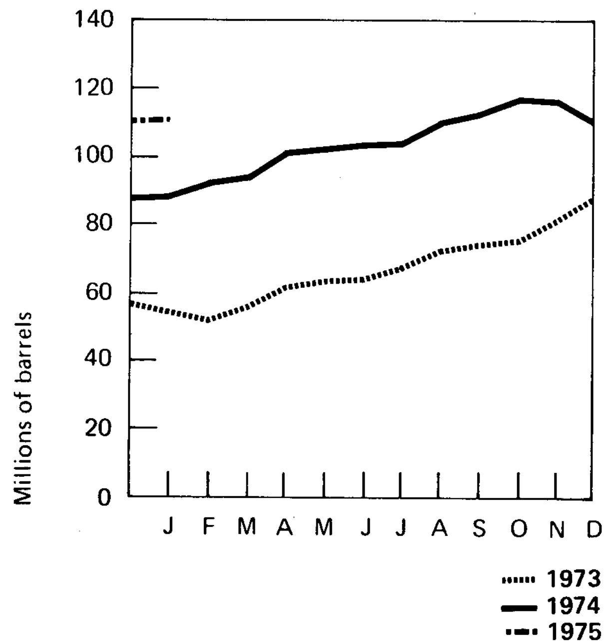
		Coal	Oil
		In thousands of short tons	In thousands of barrels
1972	January	76,876	46,055
	February	77,138	47,111
	March	80,296	52,213
	April	84,984	55,730
	May	91,778	57,399
	June	96,553	58,815
	July	93,760	60,786
	August	96,611	66,024
	September	98,396	66,004
	October	102,205	65,531
	November	102,477	62,067
	December	98,671	57,686
1973	January	95,017	53,691
	February	92,993	50,858
	March	93,986	54,885
	April	94,991	62,411
	May	98,722	64,259
	June	97,995	65,003
	July	92,215	67,987
	August	91,356	73,259
	September	90,156	74,863
	October	91,428	76,343
	November	90,369	81,224
	December	86,880	88,228
1974	January	83,366	89,053
	February	80,962	92,645
	March	84,257	94,187
	April	90,901	100,210
	May	93,628	103,606
	June	95,811	104,316
	July	91,616	105,919
	August	89,691	110,997
	September	92,704	113,570
	October	98,373	117,564
	November	93,825	116,558
	December	83,652	111,990
1975	January	81,429	110,304

Source: Federal Power Commission.

Coal Stocks



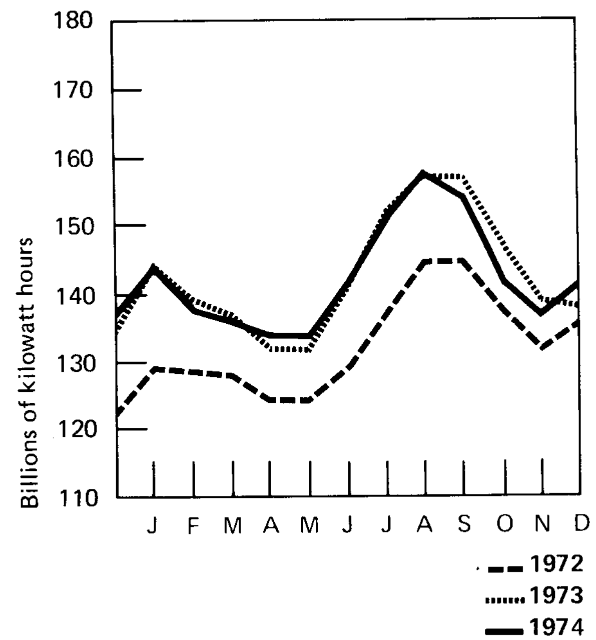
Oil Stocks



Sales

		Residential	Commercial	Industrial	Other*	Total
		In millions of kilowatt hours				
1972	January	46,353	27,965	50,526	4,579	129,423
	February	45,652	27,921	50,552	4,619	128,744
	March	43,559	27,856	52,086	4,606	128,107
	April	40,460	27,765	51,992	4,422	124,639
	May	38,044	27,983	53,489	4,430	123,946
	June	41,213	30,257	53,673	4,469	129,612
	July	47,813	32,211	52,702	4,666	137,392
	August	51,463	33,535	55,023	4,723	144,744
	September	50,888	33,522	55,548	4,928	144,886
	October	44,352	31,068	56,213	4,823	136,456
	November	41,672	29,426	55,251	4,986	131,335
	December	47,139	29,764	53,923	5,060	135,886
1973	January	52,840	31,182	55,274	5,209	144,505
	February	49,601	30,445	54,591	4,909	139,546
	March	46,315	30,100	55,866	4,822	137,103
	April	41,821	29,038	55,937	4,571	131,367
	May	39,825	30,060	56,838	4,638	131,361
	June	44,967	33,194	57,368	4,764	140,293
	July	54,123	36,147	57,152	5,140	152,562
	August	56,742	36,820	58,865	5,054	157,481
	September	56,210	36,711	59,178	5,211	157,310
	October	47,207	33,289	60,514	5,032	146,042
	November	43,175	31,363	58,464	5,085	138,087
	December	46,442	29,788	56,190	4,896	137,316
1974	January	52,846	30,608	55,754	4,995	144,203
	February	47,832	29,542	54,978	4,708	137,060
	March	46,154	29,309	55,999	4,693	136,155
	April	43,294	28,986	56,497	4,610	133,387
	May	41,215	29,876	57,386	4,685	133,162
	June	46,596	32,800	58,077	4,641	142,114
	July	53,435	35,229	57,899	4,965	151,528
	August	56,558	36,414	59,803	5,069	157,844
	September	53,252	35,830	60,366	4,983	154,431
	October	44,177	32,112	60,053	4,792	141,134
	November	42,773	30,968	57,361	4,969	136,071
	December	50,368	31,757	53,878	4,974	140,977

Total Sales



*Includes street lighting and trolley cars.
Source: Federal Power Commission.

Part 4

Nuclear Power

NUCLEAR POWER

One plant came into full commercial operation during February, Duane Arnold (515 megawatts), located near Cedar Rapids, Iowa, and owned by the Iowa Electric Light and Power Company.

In February the United States produced 55.5 percent of the total nuclear power generated by non-Communist countries.

The average U.S. lightwater reactor had a capacity of 709 megawatts, more than twice the 334-megawatt capacity of the average foreign reactor.

The U.S. capacity factor in February continued to be below the world average.

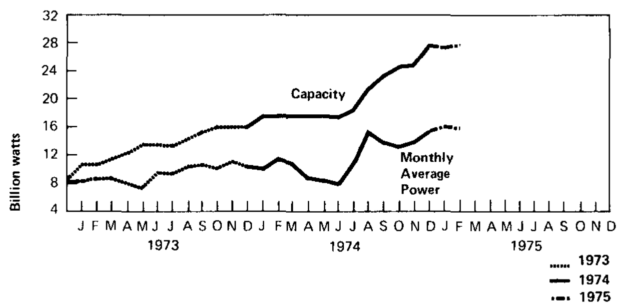
In January 1975 uranium mills were operating at only one-third of full capacity.

73.4 percent of enrichment production in February was for foreign customers.

U.S. Nuclear Powerplant Operations

		Capacity	Monthly Average Power	Percent of Total Domestic Electricity Generation
		In megawatts		
1972	January	7,349	5,720	2.9
	February	7,349	5,165	2.6
	March	7,349	5,750	3.0
	April	7,349	5,124	2.7
	May	7,349	3,918	2.1
	June	7,349	5,375	2.6
	July	7,349	6,227	2.9
	August	8,149	7,742	3.5
	September	8,149	6,589	3.2
	October	8,149	6,539	3.2
	November	8,149	7,475	3.7
	December	8,653	8,125	3.9
1973	January	10,901	8,395	3.9
	February	10,901	8,821	4.1
	March	11,701	8,991	4.5
	April	12,501	8,161	4.2
	May	13,769	7,657	3.8
	June	13,769	9,429	4.2
	July	13,769	9,355	4.0
	August	14,640	10,463	4.4
	September	15,513	10,815	4.9
	October	16,179	10,036	4.8
	November	16,179	11,308	5.7
	December	16,179	10,543	5.1
1974	January	17,734	10,230	4.9
	February	17,734	11,744	5.5
	March	17,734	11,015	5.5
	April	17,734	8,746	4.3
	May	17,734	8,254	4.0
	June	17,710	8,223	4.0
	July	18,722	11,321	4.8
	August	21,571	15,605	6.7
	September	23,667	13,894	6.6
	October	24,736	13,515	6.7
	November	24,934	14,080	6.8
	December	27,966	15,509	7.6
1975	January	27,424	16,072	7.4
	February	27,944	16,036	7.4

Sources: Capacity data and Monthly Average Power data for June 1974 forward are from U.S. Nuclear Regulatory Commission. Monthly Average Power data before June 1974 and Percent of Total Domestic Generation data are from Federal Power Commission.



Commercial Nuclear Power Generation by Major Non-Communist Countries—February 1975

Country	Number of Reactors	Capacity	Generation For Month	Capacity Factor 1975	Capacity Factor 1974
		In gross electrical magawatts	In billions of Kilowatt hours	In percent	
Canada	5	2,380	1.12	70	74
Federal Republic of Germany	7	3,450	1.52	65	57
France	10	3,050	1.63	79	57
Great Britain	29	6,140	2.81	68	61
India	3	620	0.21	51	55
Italy	3	630	0.35	83	61
Japan	8	3,890	0.98	38	61
Spain	3	1,120	0.65	87	75
Sweden	4	2,710	0.76	42	20
Switzerland	3	1,050	0.70	99	76
United States	50	35,430	13.40	56	57
Total	125	60,470	24.13	59	58

Source: Nucleonics Week Magazine.

Uranium Enrichment—February 1975

	United States	Foreign	Total
Separative Work Performed (in metric tons of separative work units)	100.31	277.06	377.37
Cost (in millions of dollars)	4.311	12.285	16.597
Product Quantity (in metric tons of uranium)	33.51	97.89	131.40
Average Enrichment (in percent U-235)	2.354	2.300	2.314
Feed Requirement (in metric tons of uranium)	141.24	402.39	543.63

Source: U.S. Energy Research and Development Administration.

Summary of Monthly Nuclear Fuel Cycle—January 1975

FUEL CYCLE ACTIVITY	PRODUCT	QUANTITY				COST
		Processed Material*	**Percent Utilization of Industry Capacity**	**Energy Content of Processed Material****	**Energy Consumed in Fuel Cycle Activity*****	**Contribution to Electric Power+**
		In MTU except where noted		In billion Btu except where noted		In mills per kilowatt hour
Milling	Yellowcake (U_3O_8) Deliveries	371	33	130,000	243	0.54
Conversion	Uranium Hexafluoride (UF_6) Deliveries	1,099	75	375,000	236	0.07
Enrichment	Enriched UF Delivered[6]	147 (590 MT-SWU)	++	301,000	17,151	0.86
Fabrication	Uranium Dioxide (UO_2) in Fuel Assemblies	150	61	307,000	95	0.46
	Unused UO_2 at Reactor Sites	30	–	–	–	–
Powerplant Operation	Electricity Generated	12,568 (Thousand MWhe)	59	–	610,000 (MWhe)	–
	Spent Fuel Discharged	0	–	–	–	–
Reprocessor	Spent Fuel Received	236	–	–	–	–
	Spent Fuel Reprocessed	0	–	–	–	–

*Units of measure are discussed in Explanatory Notes 3 and 4.
**Assumes 25,000 MWD/MTU for heat content of enriched uranium and a 6:1 feed-to-product ratio at the enrichment plant.
***Energy requirements for processing obtained from U.S.A.E.C. Report No. WASH-1148.
+Cost contribution is computed from unit prices paid for current month's production and requirement for a 1000-Mwe reactor operating at 80 percent capacity factor, given in AEC Report No. WASH 1174-74. Because of the long lead times required for nuclear fuel processing, the sum of the numbers in this column does not necessarily reflect the fuel cost of current electricity production.
++ERDA's enrichment plants are presently operating at maximum utilization of available electric power with the excess production being placed in the "preproduction stockpile" in anticipation of high demand for enrichment in the 1980's.
Source: FEA.

ENERGY CONSUMPTION

Domestic energy consumption in December 1974 was 6.741 quadrillion Btu.

For 1974, total consumption, at 73.386 quadrillion Btu, was 1.7 percent below the 1973 level of 74.647 quadrillion Btu.

1.768 quadrillion Btu were expended to generate and transmit electricity in December. For the year, 20.518 quadrillion Btu were expended in this manner.

Energy consumption by the Residential and Commercial Sector was 2.426 quadrillion Btu in December 1974; 30.9 percent was consumed in the form of dry natural gas, 23.7 percent was petroleum products, and 44.2 percent was in the form of electricity. During 1974, this sector consumed 25.702 quadrillion Btu.

The Industrial Sector consumed 2.657 quadrillion Btu during December 1974, 44.3 percent of which was dry natural gas, 19.7 percent was in the form of petroleum products, 10.5 percent was in the form of coal, and 25.4 percent was in the form of electricity. For the year, this sector consumed a total of 28.942 quadrillion Btu.

The Transportation Sector consumed 1.658 quadrillion Btu in December, almost all of which was petroleum products (94.6 percent). In 1974, a total of 18.742 quadrillion Btu was consumed by the Transportation Sector.

FORECAST PETROLEUM CONSUMPTION

Total demand for petroleum products during the 4 weeks ending March 14 was 17.18 million barrels per day, which was 70,000 barrels per day below the forecast of 17.25 million barrels per day.

Domestic demand for motor gasoline for the 4 weeks ending March 14 was 6.45 million barrels per day, which was 190,000 barrels per day above the forecast level of 6.26 million barrels per day.

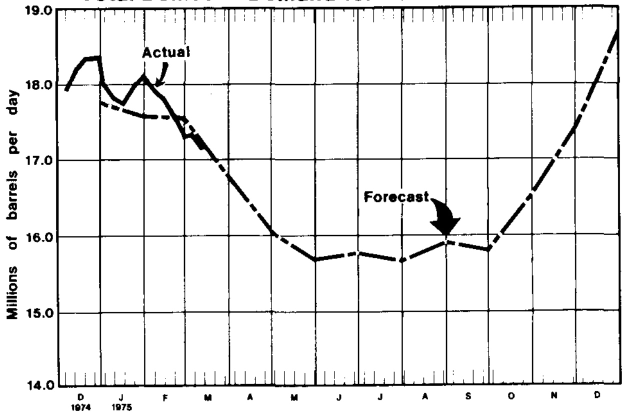
Domestic demand for distillate fuel oil for the 4 weeks ending March 14 was 3.71 million barrels per day, essentially equal to the forecast of 3.70 million barrels per day.

Domestic demand for residual fuel oil for the 4 weeks ending March 14 was 2.60 million barrels per day, which was 107,000 barrels per day above the forecast of 2.50 million barrels per day.

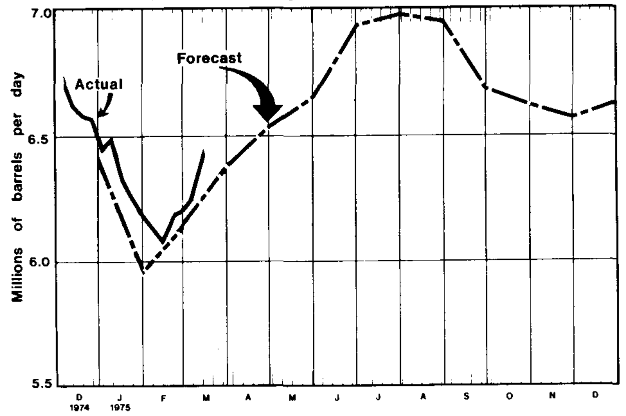
Part 5 Consumption

Forecast Petroleum Consumption

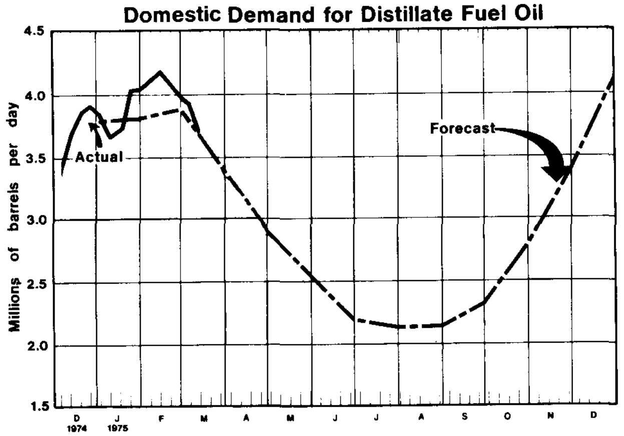
Total Domestic Demand for Petroleum Products



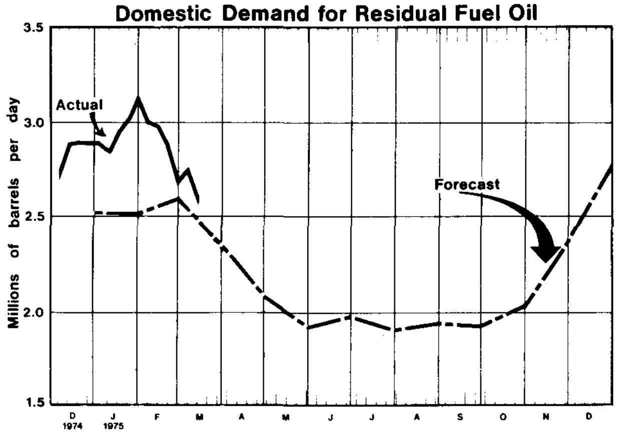
Domestic Demand for Motor Gasoline



Domestic Demand for Distillate Fuel Oil



Domestic Demand for Residual Fuel Oil



Key

Domestic Demand — Demand for products, in terms of real consumption, is not available; production plus imports plus withdrawals from primary stocks is used as a proxy for consumption. Secondary stocks, not measured by FEA, are substantial for some products.

Actuals — Four-week moving averages.

Forecast — Forecast petroleum product demand assumes normal weather conditions and projected economic activity. The forecast is periodically revised to take into account actual weather conditions and revised macroeconomic forecasts. A more thorough description of FEA's forecasting procedures will appear in next month's issue.

Part 6

Resource Development

OIL AND GAS EXPLORATION

An average of 1,611 rotary rigs were engaged in oil and gas drilling operations during February 1975, an increase of 256 rigs, or 19 percent, over the rig count for February 1974.

There were 196 more oil wells, but 142 fewer gas wells, drilled in February 1975 compared with February 1974. Total wells drilled (oil + gas + dry holes) for the month, at 2,488, represented an increase of 7 percent over last February.

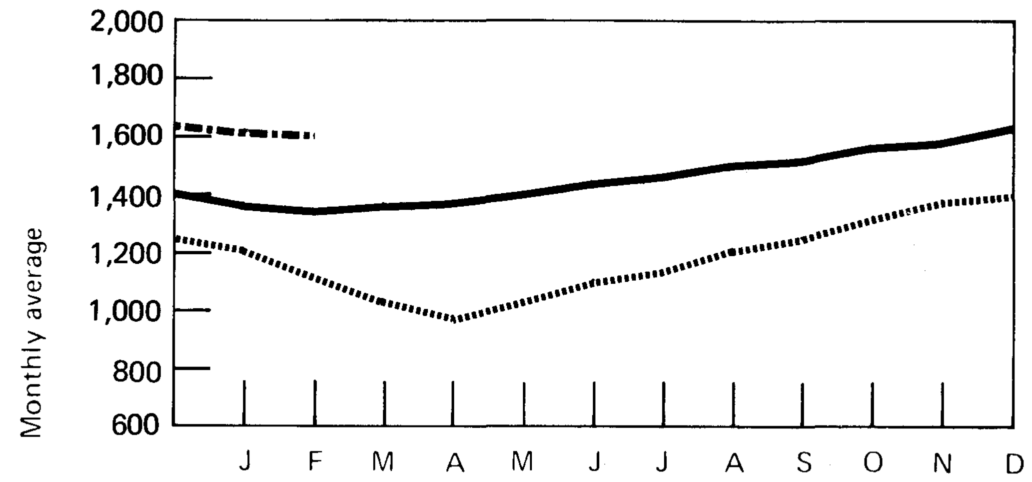
The number of seismic crews engaged in offshore oil and gas exploration declined to 24 in February 1975 from an average of 35 to 40 in operation during mid-1974. Four additional onshore crews were activated during February, however, for a total crew count of 302 for the month.

Oil and Gas Exploration

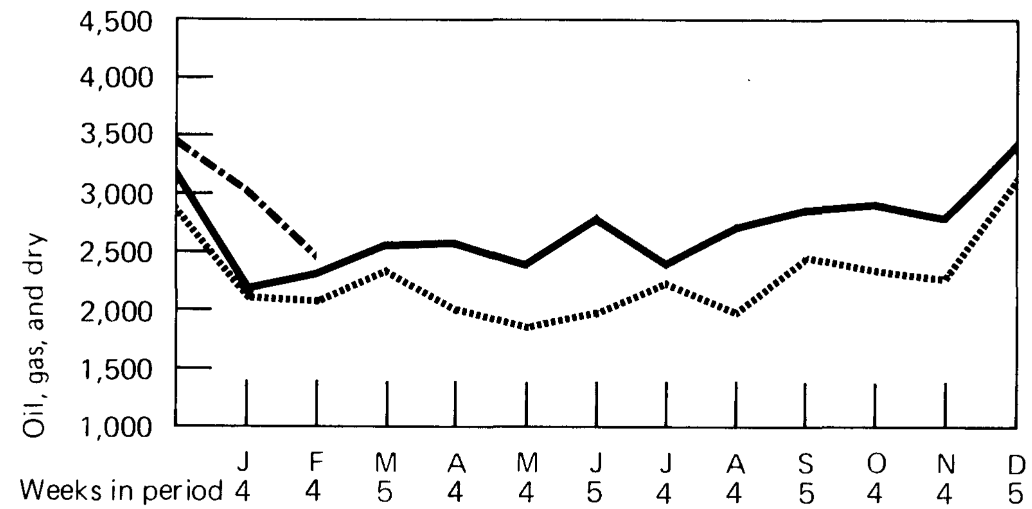
		Rotary Rigs in Operation	Wells Drilled				Total Footage of Wells Drilled
		Monthly average	Oil	Gas	Dry	Total	
1972	January	1,147	807	281	851	1,939	9,441,238
	February	1,071	965	350	955	2,270	12,381,669
	March	1,034	1,210	394	889	2,493	12,406,433
	April	1,002	923	355	788	2,066	9,902,253
	May	1,005	920	332	816	2,068	10,218,488
	June	1,049	1,042	395	903	2,340	11,009,513
	July	1,104	833	335	795	1,963	9,212,931
	August	1,130	946	410	924	2,280	11,334,867
	September	1,152	1,065	468	1,009	2,542	11,634,026
	October	1,165	792	539	919	2,250	10,944,312
	November	1,186	860	535	975	2,370	12,360,912
	December	1,241	985	536	1,290	2,811	14,190,138
1973	January	1,219	758	406	899	2,063	10,972,665
	February	1,126	777	487	765	2,029	10,655,936
	March	1,049	953	504	909	2,366	12,317,756
	April	993	699	489	777	1,965	10,433,987
	May	1,046	749	407	647	1,803	9,622,110
	June	1,118	767	432	795	1,994	10,814,600
	July	1,155	912	504	840	2,256	10,995,939
	August	1,222	724	456	739	1,919	9,632,819
	September	1,266	854	690	940	2,484	12,075,280
	October	1,334	790	554	958	2,302	11,693,672
	November	1,390	822	606	865	2,293	11,823,350
	December	1,405	1,087	827	1,208	3,122	15,529,582
1974	January	1,372	763	577	803	2,143	10,391,797
	February	1,355	901	600	816	2,317	12,160,308
	March	1,367	936	638	1,003	2,577	12,844,135
	April	1,381	947	700	945	2,592	13,349,007
	May	1,412	957	520	870	2,347	11,459,595
	June	1,432	1,238	586	982	2,806	12,976,388
	July	1,480	1,008	461	884	2,353	11,801,777
	August	1,518	1,210	555	968	2,733	12,409,855
	September	1,527	1,200	600	1,091	2,891	12,676,090
	October	1,584	1,131	551	1,241	2,923	14,080,534
	November	1,596	1,088	626	1,053	2,767	11,794,937
	December	1,643	1,339	791	1,274	3,404	15,707,092
1975	January	1,615	1,299	655	1,040	2,994	13,189,222
	February	1,611	1,097	458	933	2,488	12,070,712

Sources: Rotary Rigs - Hughes Tool Company.
Wells - American Petroleum Institute.

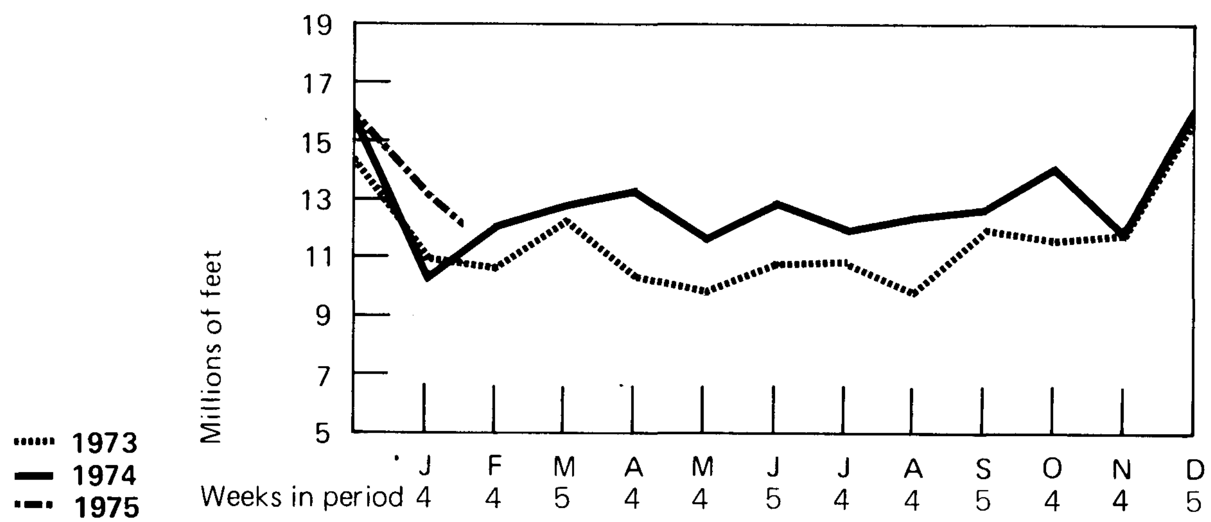
Rotary Rigs in Operation



Total Wells Drilled

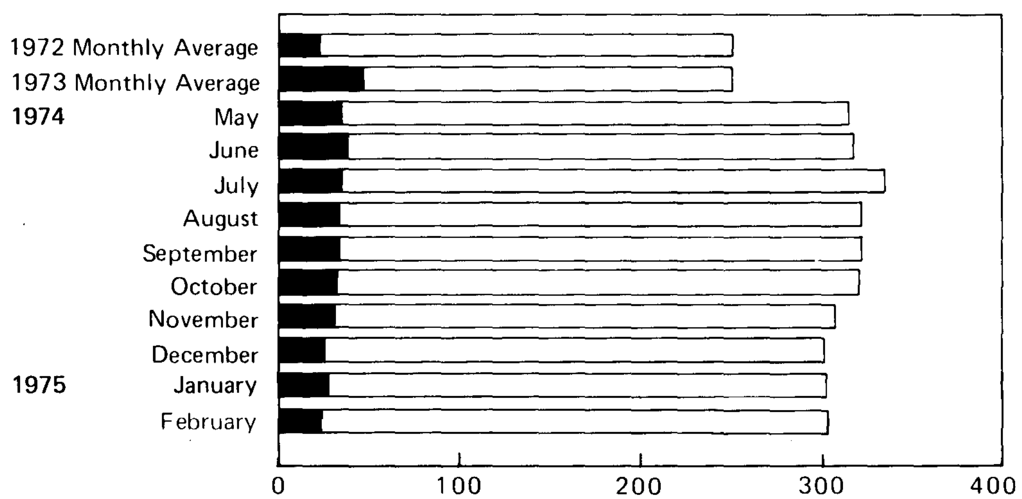


Total Footage of Wells Drilled

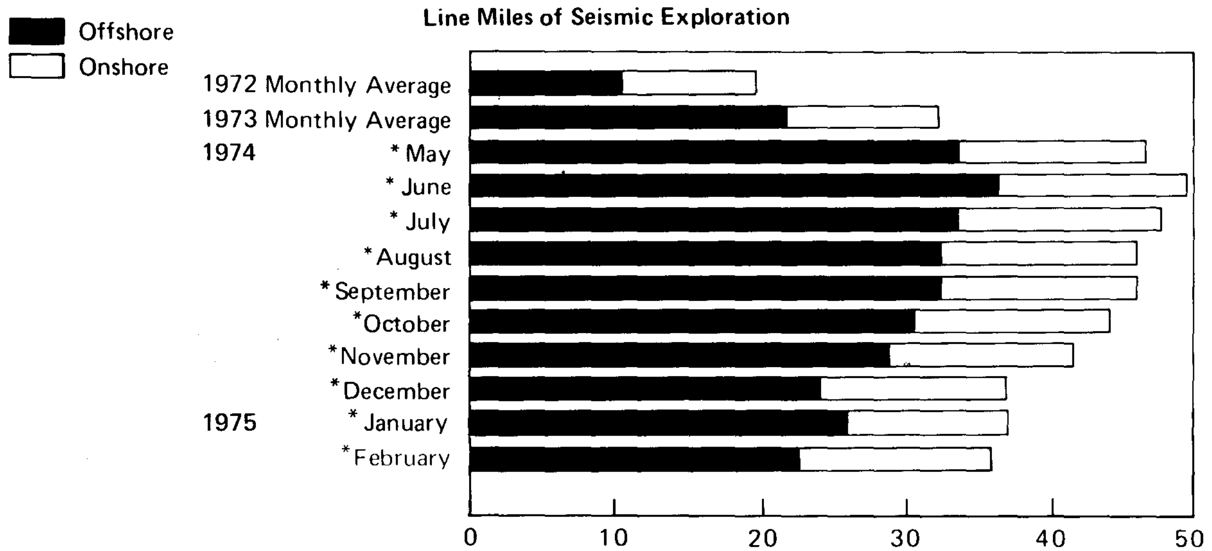


	Crews Engaged in Seismic Exploration			Line Miles of Seismic Exploration		
	Offshore	Onshore	Total	Offshore	Onshore	Total
1972 Monthly Average	12	239	251	10,306	9,333	19,639
1973 Monthly Average	23	227	250	21,579	10,597	32,175
1974					Estimates*	
May	35	278	313	33,320	13,066	46,386
June	38	279	317	36,176	13,113	49,289
July	35	299	334	33,320	14,053	47,373
August	34	287	321	32,368	13,489	45,857
September	34	287	321	32,368	13,489	45,857
October	32	288	320	30,464	13,586	44,000
November	30	276	306	28,564	12,972	41,532
December	25	275	300	23,800	12,925	36,725
1975						
January	27	274	301	25,704	12,878	38,582
February	24	278	302	22,848	13,066	35,914

Crews Engaged in Seismic Exploration



Line Miles of Seismic Exploration



Thousands of miles

*See Explanatory Note 13. Source: Society of Exploration Geophysicists.

Part 7 Price

MOTOR GASOLINE

The average nationwide retail price of regular gasoline remained relatively stable during February, increasing only 0.1 cent to 52.5 cents per gallon. The average price that retailers paid for regular gasoline also increased 0.1 cent per gallon (for the third consecutive month) bringing this price to 43.5 cents per gallon.

During February, the average nationwide selling price of regular gasoline by major retail gasoline dealers was 4.3 cents per gallon greater than that of independents, a drop of 0.2 cent per gallon from January.

The national average price of diesel fuel sold in truck stops during February was 49.7 cents per gallon, compared with an average price of 50.2 cents per gallon for diesel fuel sold in retail gasoline service stations.

Regional gasoline prices ranged from a low of 50.6 cents per gallon in the Gulf Coast Region to 54.2 cents per gallon in the Mid-Atlantic Region.

A survey druing February of 21 major oil companies indicated that eight of the Nation's largest marketers of gasoline increased prices and only two decreased prices.

For these 21 companies, the average DTW price to branded retail outlets increased 0.29 cent per gallon from its January level. The average price paid by branded jobbers rose 0.28 cent per gallon, resulting in an increase of 0.01 cent per gallon on their margins.

HEATING OIL

Heating oil distributors decreased prices of heating oil sold to residential customers by 0.1 cent per gallon during January, which reflected an ample supply of heating oil on the market.

A survey of 21 major oil companies indicated that heating oil prices remained relatively unchanged during February. A total of 4 companies decreased prices, 4 increased prices, and 13 did not change prices.

CRUDE OIL

New and released oil accounted for 14 and 8 percent, respectively, of total domestic crude oil production during December. Production of old oil declined 1 percentage point to 66 percent. Stripper well production accounted for the remaining 12 percent.

The average wellhead price of new oil in January increased 20 cents per barrel to $11.28 per barrel.

The preliminary cost of imported crude petroleum to refiners decreased 19 cents per barrel in January.

The preliminary average cost of domestic crude to the refiner rose a substantial 31 cents per barrel in January to $7.70 per barrel.

The preliminary composite cost of crude oil to refiners during January was $9.56 per barrel, and increase of 28 cents per barrel over December.

UTILITY FOSSIL FUELS

The national average cost of fossil fuels delivered to utilities during the month increased a substantial 13.6 cents per million Btu over the October level. On a percentage basis, this was the largest monthly increase (13.9 percent) since January 1974. The Middle Atlantic and Pacific Regions exhibited the largest fuel cost increases at 31.6 cents and 24.9 cents per million Btu, respectively.

The national average cost of coal increased more in November than in any month during 1974 (9.4 cents per million Btu). Regionally, the largest increase occurred in the East North Central Region (15.5 cents per million Btu) which depends heavily upon coal as a utility fuel.

November residual fuel prices remained relatively stable compared with the previous month, rising only 0.7 cent per million Btu. The largest gain (11.2 cents per million Btu) occurred in the West North Central Region, and the greatest decline (6.3 cents per million Btu) was in the West South Central Region.

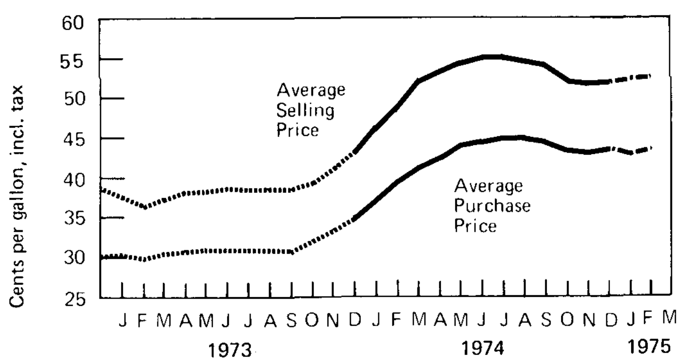
The average price of natural gas in November 1974 registered another slight increase on a national level, continuing the gradual upward trend that began in January 1974. No significant regional fluctuations were noted during the month.

Motor Gasoline

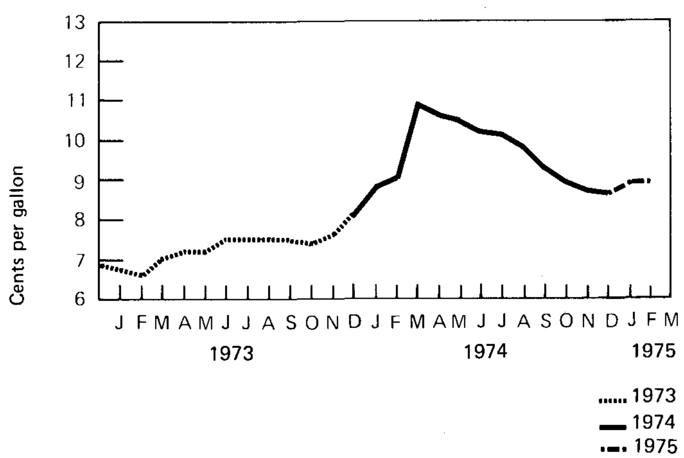
Regular Gasoline at Retail Outlets

	Average Selling Price	Average Purchase Price	Average Dealer Margin
	Cents per gallon, including tax*		
1973 January	37.3	30.5	6.8
February	36.8	30.1	6.7
March	37.9	30.8	7.1
April	38.3	31.0	7.3
May	38.5	31.2	7.3
June	38.8	31.2	7.6
July	38.8	31.2	7.6
August	38.8	31.2	7.6
September	38.7	31.1	7.6
October	39.7	32.2	7.5
November	41.3	33.6	7.7
December	43.3	35.1	8.2
1974 January	46.3	37.4	8.9
February	48.8	39.7	9.1
March	52.3	41.4	10.9
April	53.4	42.7	10.7
May	54.7	44.1	10.6
June	55.1	44.8	10.3
July	55.2	45.0	10.2
August	54.9	45.1	9.8
September	54.2	44.8	9.4
October	52.4	43.4	9.0
November	52.0	43.2	8.8
December	52.0	43.3	8.7
1975 January	52.4	43.4	9.0
February	52.5	43.5	9.0

Average Retail Prices For Regular



Average Margins For Regular



*To derive prices excluding taxes, 12.0 cents per gallon may be deducted for 1973 and 12.2 cents per gallon may be deducted for 1974 and 1975.

Sources: Platts Oilgram through September 1973. FEA from October 1973 through December 1974. Lundberg Survey, Inc., from January 1975 forward.

Average Selling Prices at Major and Independent Retail Outlets—February 21, 1975

	Cents per gallon, including tax
Regular Gasoline	
Major	53.1
Independent	48.8
National Average	52.5
Premium Gasoline	
Major	57.8
Independent	53.0
National Average	57.3
Diesel Fuel*	
Truck Stops	
Major	51.1
Independent	48.1
National Average	49.7
Service Stations	
Major	51.5
Independent	48.9
National Average	50.2

*See Explanatory Note 14.
Source: Lundberg Survey, Inc.

Average Margins for Major and Independent Retail Dealers

	Cents per gallon
Regular Gasoline	
Major	9.3
Independent	7.3
National Average	9.0
Diesel Fuel*	
Truck Stops	
Major	6.6
Independent	7.8
National Average	7.0
Service Stations	
Major	7.0
Independent	7.9
National Average	7.3

*See Explanatory Note 14.
Source: Lundberg Survey, Inc.

Average Regional Retail Selling Prices and Dealer Margins for Regular Gasoline—February 21, 1975

FEA Region	Selling Price	Margin
	Cents per gallon, including tax	
1A New England	52.5	9.4
1B Mid Atlantic	54.2	8.7
1C Lower Atlantic	52.7	9.0
2 Mid Continent	52.1	8.5
3 Gulf Coast	50.6	10.3
4 Rocky Mountain	52.4	9.5
5 West Coast	54.0	9.2
National Average	52.5	9.0

Source: Lundberg Survey, Inc.

Motor Gasoline (Continued)

Retail Gasoline Price Changes for Major Oil Companies During February 1975

Company	Effective Date	Amount of Change Cents per gallon
Amerada Hess		None
American Petrofina	February 11	0.5
Ashland	February 26	1.0 (Twin Cities)
Atlantic Richfield	February 25	-1.0
B.P.	February 27	1.0
Cities Service	February 25	1.5
Champlin	February 6	1.0
Continental		None
Exxon		None
Getty		None
Gulf		None
Kerr-McGee	February 1	2.0
Mobil	February 20	-1.0
Phillips		None
Shell	February 28	2.0
Standard Oil of California		None
Standard Oil of Indiana		None
Standard Oil of Ohio	February 27	1.0
Sun	February 13	2.0
Texaco		None
Union Oil of California		None

Source: FEA Survey.

Major Brand Regular Gasoline, February 1975

Marketing Region	Retail DTW Price	Change from Previous Month	Branded Jobber Price	Change from Previous Month	Regional Jobber Margin	Change from Previous Month
			Cents per gallon			
Northeast	32.78	0.50	28.37	0.60	4.41	-0.10
Mid Atlantic	32.11	0.47	28.24	0.49	3.87	-0.02
Southeast	31.58	0.41	27.77	0.42	3.81	-0.01
Central	32.80	0.68	28.65	0.48	4.15	0.20
Western	32.06	-0.14	28.31	-0.15	3.75	0.01
Southwest	31.56	0.42	27.57	0.40	3.99	0.02
Pacific	31.23	-0.31	27.49	-0.30	3.74	-0.01
Average	32.02	0.29	28.06	0.28	3.96	0.01

Source: FEA Survey.

Heating Oil

Average Prices for January 1975

	Average Purchase Price	Residential Selling Price	Residential Margin	Institutional and Utility Selling Price	Institutional and Utility Margin	Industrial Selling Price	Industrial Margin
			Cents per gallon				
New England	29.8	38.6	8.8	36.7	6.9	36.4	6.6
Mid Atlantic	29.5	37.5	8.0	36.1	6.6	36.5	7.0
Southeast	28.9	36.0	7.1	35.1	6.2	35.4	6.5
East North Central	26.1	32.7	6.6	32.0	5.9	32.9	6.8
West North Central	27.4	33.0	5.6	32.8	5.4	33.0	5.6
East South Central	NA	NA	NA	NA	NA	NA	NA
Mountain	30.1	37.0	6.9	35.2	5.1	34.0	3.9
West Coast	29.8	38.5	8.7	36.6	6.8	36.1	6.3
National Average	28.8	36.2	7.4	34.9	6.1	34.9	6.1

NA = Not available.
Source: FEA.

Price Changes for Major Oil Companies During February 1975

Company	Effective Date	Amount of Change Cents per gallon
Amerada Hess		None
American Petrofina		None
Ashland		None
Atlantic Richfield	February 25	-2.0
B.P.	February 27	2.0 (Ohio)
Cities Service		None
Champlin		None
Continental		None
Exxon		None
Getty		None
Gulf		None
Kerr–McGee	February 1	-1.0
Mobil	February 20	-1.0
Phillips		None
Shell		None
Standard Oil of California		None
Standard Oil of Indiana	February 3	2.6
Standard Oil of Ohio	February 27	2.0 (Ohio)
Sun	February 13	2.0
Texaco	February 21	-1.5 (East); -4.0 (Mid and Far West)
Union Oil of California		None

Source: FEA Survey.

Crude Oil

Percentage of Domestic Production Sold at Controlled and Uncontrolled Prices

		Controlled	Uncontrolled		
		Old Oil	New Oil	Released	Stripper
1974	January	60	17	10	13
	February	62	15	10	13
	March	60	16	11	13
	April	60	16	11	13
	May	62	15	10	13
	June	63	15	9	13
	July	64	15	9	12
	August	66	14	8	12
	September	67	13	8	12
	October	66	14	8	12
	November	67	13	8	12
	December	66	14	8	12

Source: FEA.

Domestic Crude Petroleum Prices at the Wellhead

		Old	New
		Dollars per barrel	
1974	January	5.25	9.82
	February	5.25	9.87
	March	5.25	9.88
	April	5.25	9.88
	May	5.25	9.88
	June	5.25	9.95
	July	5.25	9.95
	August	5.25	9.98
	September	5.25	10.10
	October	5.25	10.74
	November	5.25	10.90
	December	5.25	11.08
1975	January	5.25	*11.28

*Preliminary estimate.
Source: FEA.

Refiner Acquisition Cost of Crude Petroleum*

		Domestic	Imported	Composite
		Dollars per barrel		
1974	January	6.72	9.59	7.46
	February	7.08	12.45	8.57
	March	7.05	12.73	8.68
	April	7.21	12.72	9.13
	May	7.26	13.02	9.44
	June	7.20	13.06	9.45
	July	7.19	12.75	9.30
	August	7.20	12.68	9.17
	September	7.18	12.53	9.13
	October	7.26	12.44	9.22
	November	7.46	12.53	9.41
	December	7.39	12.82	9.28
1975	January	**7.70	**12.63	**9.56

**Preliminary data.
Source: FEA.

Estimated Landed Cost of Imported Crude Petroleum From Selected Countries*

		Algeria	Canada	Indonesia	Iran	Nigeria	Saudi Arabia	U. A. Emirates	Venezuela
					Dollars per barrel				
1973	December	NA	6.32	6.42	6.37	8.54	5.49	NA	6.70
1974	January	NA	6.70	NA	8.53	12.13	NA	NA	10.28
	February	NA	10.90	NA	12.11	12.74	NA	NA	11.31
	March	NA	11.14	12.13	13.02	13.26	NA	NA	11.78
	April	13.63	11.02	12.49	12.83	13.67	11.59	NA	11.38
	May	14.67	11.47	12.95	13.84	13.83	11.53	NA	11.28
	June	14.43	12.56	13.21	13.44	13.03	11.32	13.06	10.39
	July	13.65	12.65	13.77	13.02	12.75	11.97	12.34	10.64
	August	13.96	12.49	14.38	12.31	12.70	12.16	12.69	11.20
	September	13.83	12.51	13.42	11.87	12.28	11.45	NA	11.01
	October	13.20	12.53	14.24	12.07	12.12	11.51	12.84	10.95
	November	13.43	12.33	13.45	12.15	R12.83	12.15	R13.54	11.15
	December	13.08	12.15	14.15	11.63	12.88	11.75	14.59	11.37

NA = Not available.
R = Revised data.
Source: FEA.
*See Explanatory Note 15.

Utility Fossil Fuels

COST OF FOSSIL FUELS DELIVERED TO STEAM-ELECTRIC UTILITY PLANTS

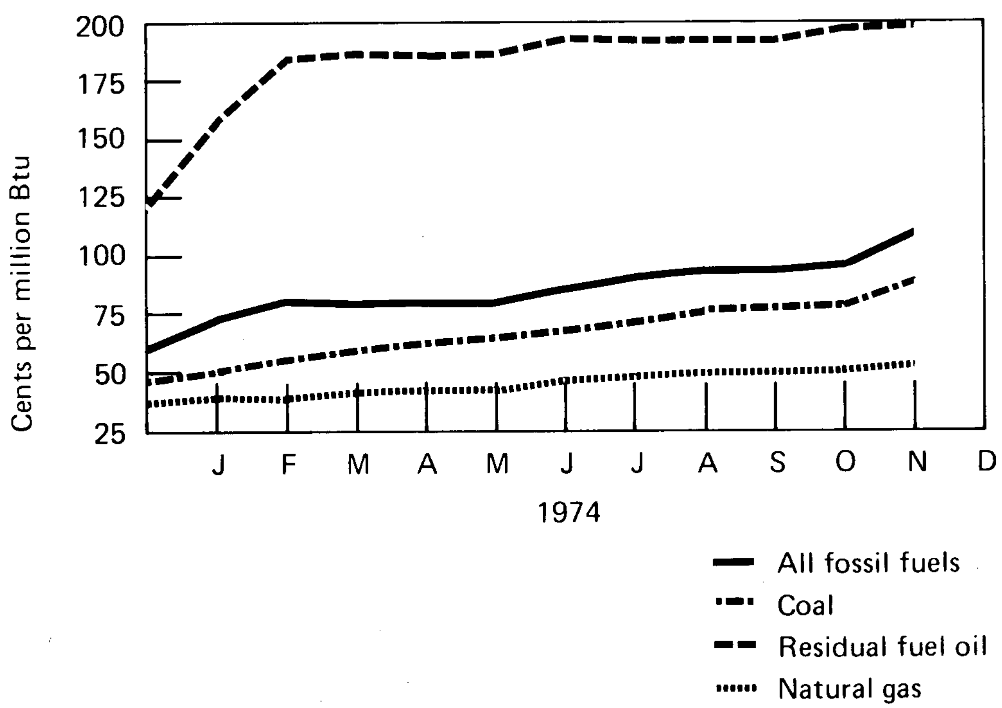
All Fossil Fuels*

Cents per million Btu

Region 1974	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV
New England	147.7	175.7	192.7	186.8	180.0	184.7	186.2	191.4	191.6	192.6	198.7
Middle Atlantic	111.6	129.0	123.9	124.9	124.2	137.6	144.7	147.8	137.5	139.1	170.7
East North Central	52.5	57.0	62.3	63.7	68.9	76.9	79.1	82.7	82.5	84.6	102.0
West North Central	47.8	40.5	36.5	42.4	43.9	47.2	45.3	50.3	51.0	50.0	60.0
South Atlantic	88.5	100.6	102.8	105.9	109.8	119.0	123.7	128.2	132.3	128.4	144.3
East South Central	46.0	52.4	54.1	54.4	58.3	62.5	65.7	68.2	69.7	75.2	86.7
West South Central	48.9	46.2	48.0	44.1	47.3	50.0	59.4	57.1	52.1	53.7	58.0
Mountain	43.7	48.1	42.7	43.1	36.3	40.3	45.0	46.8	45.0	47.8	45.8
Pacific	119.7	160.3	114.1	117.8	122.4	117.9	118.9	118.8	127.3	132.8	157.7
National Average	74.4	81.6	80.9	81.1	81.2	87.7	92.2	95.4	95.9	97.7	111.3

*See Explanatory Note 16.

National Average



Coal

Cents per million Btu

Region 1974	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV
New England	102.8	114.2	132.0	136.8	128.8	95.9	106.8	93.7	93.9	110.3	108.0
Middle Atlantic	60.2	69.5	73.1	80.8	79.3	88.6	94.3	97.4	95.2	94.6	117.4
East North Central	48.9	52.4	57.4	59.2	65.3	71.7	73.0	77.7	78.1	79.5	95.0
West North Central	36.7	36.3	37.7	41.0	41.7	42.0	44.0	48.3	50.5	48.7	57.0
South Atlantic	66.3	76.7	81.7	85.3	88.0	90.2	100.4	107.5	114.5	112.6	126.8
East South Central	43.3	49.8	51.6	52.7	54.2	57.9	57.7	61.6	64.1	69.7	77.8
West South Central	13.6	13.6	13.6	13.6	13.6	17.7	17.7	17.7	17.7	21.0	21.0
Mountain	25.9	26.8	26.1	26.7	24.9	25.7	25.0	25.1	25.1	26.7	28.3
Pacific	35.0	NA	35.1	35.3	35.6	35.5	37.8	38.3	39.0	38.5	38.6
National Average	51.4	56.9	60.8	64.0	65.8	69.5	72.9	77.3	79.1	80.9	90.3

Residual Fuel Oil*

Cents per million Btu

Region 1974	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV
New England	156.6	190.5	208.1	199.4	193.1	201.1	199.2	201.8	199.8	202.0	207.5
Middle Atlantic	186.5	208.1	212.2	196.0	208.6	207.7	208.6	204.5	200.7	205.4	205.7
East North Central	110.3	127.2	158.3	183.6	138.7	198.2	182.7	164.4	161.5	161.3	167.1
West North Central	160.0	154.8	169.1	178.2	160.9	179.3	152.7	178.1	182.6	179.5	190.7
South Atlantic	140.6	167.3	172.7	172.8	174.9	181.5	178.7	178.9	179.3	183.3	182.2
East South Central	112.5	132.2	136.0	153.0	164.9	171.5	169.6	172.6	173.9	171.8	167.9
West South Central	107.5	126.8	144.6	159.4	152.1	161.1	187.5	179.3	180.8	186.0	179.7
Mountain	159.2	174.9	172.1	174.1	194.4	199.2	176.2	179.0	186.7	185.0	185.1
Pacific	155.5	191.2	161.8	180.8	188.7	202.5	204.9	220.3	222.3	223.8	219.5
National Average	158.2	185.9	188.0	186.5	188.1	194.9	194.2	194.6	194.3	198.2	198.9

Natural Gas**

Cents per million Btu

Region 1974	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV
New England	57.1	73.3	134.2	116.4	116.3	124.7	138.7	141.2	132.5	NA	NA
Middle Atlantic	64.2	72.7	72.4	59.5	59.3	77.3	85.2	74.2	80.5	64.8	70.0
East North Central	63.8	62.4	65.7	60.1	72.0	76.1	77.3	80.5	84.3	83.3	80.3
West North Central	35.7	38.0	39.5	41.2	41.8	41.7	42.1	43.3	43.8	43.0	44.8
South Atlantic	51.7	57.3	61.9	63.2	57.8	59.8	60.9	58.3	55.8	58.5	60.2
East South Central	45.5	48.1	47.7	50.7	50.5	52.8	63.3	58.9	71.2	74.3	76.9
West South Central	32.9	35.2	37.6	39.1	39.5	43.6	43.8	46.8	46.0	47.8	51.5
Mountain	47.9	54.5	48.4	48.3	48.8	49.2	50.8	49.5	52.1	55.7	56.6
Pacific	48.2	47.6	46.6	49.8	50.4	50.7	60.0	64.0	64.7	65.9	64.0
National Average	37.3	39.8	42.5	43.6	44.0	47.9	49.8	51.8	52.4	53.2	54.0

NA = Not available.
*See Explanatory Note 16.
**Includes small quantities of coke oven gas, refinery gas, and blast furnace gas.
Source: Federal Power Commission.

Definitions

Base Production Control Level
The total number of barrels of domestic crude petroleum produced from a particular property in the corresponding month of 1972.

Ceiling Price
The maximum permissible selling price for a particular grade of domestic crude petroleum in a particular field is the May 15, 1973, posted price plus $1.35 per barrel.

Controlled Crude Oil
Domestically produced crude petroleum that is subject to the ceiling price for crude oil. For a particular property which is not a stripper-well lease, the volume of controlled oil equals the base production control level minus an amount of released oil equal to the new oil production from that property.

Crude Oil Domestic Production
The volume of crude oil flowing out of the ground. Domestic production is measured at the wellhead and includes lease condensate, which is a natural gas liquid recovered from lease separators or field facilities.

Crude Oil Imports
The monthly volume of crude oil imported which is reported by receiving refineries, including crude oil entering the U.S. through pipelines from Canada.

Crude Oil Input to Refineries
Total crude oil used as input for the refining process, less crude oil lost or used for refinery fuel.

Crude Oil Stocks
Stocks held at refineries and at pipeline terminals. Does not include stocks held on leases (storage facilities adjacent to the wells), which historically total approximately 13 million barrels.

Dealer Tankwagon (DTW) Price
The price at which a retail dealer purchases gasoline from a distributor or a jobber.

Distillate Fuel Oil
The lighter fuel oils distilled off during the refining process. Included are products known as ASTM grades Nos. 1 and 2 heating oils, diesel fuels, and No. 4 fuel oil. The major uses of distillate fuel oils include heating, fuel for on- and off-highway diesel engines, and railroad diesel fuel. Minor quantities of distillate fuel oils produced and/or held as stocks at natural gas processing plants are not included in this series.

Domestic Demand for Refined Petroleum Products
A calculated value, computed as domestic production plus net imports (imports less exports), less the net increase in primary stocks. It, therefore, represents the total disappearance of refined products from primary supplies.

Domestic Non-controlled Crude Oil
That portion of domestic crude oil production including new, released, and stripper oil which may be sold at a price exceeding the ceiling price.

Electricity Production
Production at electric utilities only. Does not include industrial electricity generation.

Firm Natural Gas Service
High priority gas service in which the pipeline company is under contract to deliver a specified volume of gas to the customer on a non-interruptible basis. Residential and small commercial facilities usually fall into this category.

Interruptible Natural Gas Service
Low priority gas service in which the pipeline company has the contractual option to temporarily terminate deliveries to customers by reason of claim of firm service customers or higher priority users. Large commercial facilities, industrial users, and electric utilities usually fall into this category.

Jet Fuel
Includes both naphtha-type and kerosine-type fuels meeting standards for use in aircraft turbine engines. Although most jet fuel is used in aircraft, some is used for other purposes, such as for generating electricity in gas turbines.

Jobber
A petroleum distributor who purchases refined product from a refiner or terminal operator for the purpose of reselling to retail outlets and commercial accounts or for the purpose of retailing through his own retail outlets.

Jobber Margin
The difference between the price at which a jobber purchases refined product from a refiner or terminal operator and the price at which the jobber sells to retail outlets. This does not reflect margins obtained by jobbers through retail sales or commercial accounts.

Jobber Price
The price at which a petroleum jobber purchases refined product from a refiner or terminal operator.

Landed Cost
The cost of imported crude oil equal to actual cost of crude at point of origin plus transportation cost to the United States.

Line Miles of Seismic Exploration
The distance along the earth's surface that is covered by seismic traverses.

Motor Gasoline Production
Total production of motor gasoline by refineries, measured at refinery outlet. Relatively small quantities of motor gasoline are produced at natural gas processing plants, but these quantities are not included.

Motor Gasoline Stocks
Primary motor gasoline stocks held by gasoline producers. Stocks at natural gas processing plants are not included.

Natural Gas Imports
This is based on data collected by the Federal Power Commission from major interstate pipeline companies.

Natural Gas Liquids
Products obtained from natural gasoline plants, cycling plants, and fractionators after processing the natural gas. Included are ethane, liquified petroleum (LP) gases (propane, butane, and propane-butane mixtures), natural gasoline, plant condensate, and minor quantities of finished products such as gasoline, special naphthas, jet fuel, kerosine, and distillate fuel oil.

Natural Gas Marketed Production
Gross withdrawals from the ground, less gas used for repressuring and quantities vented and flared. Gas volumes are reported at a base pressure of 14.73 pounds per square inch absolute at 60°F. Data are from Bureau of Mines and are collected from reports received from the Interstate Oil Compact Commission provided by State agencies.

New Oil
The volume of domestic crude petroleum produced from a property in a specific month which exceeds the base production control level for that property.

Old Oil
Same as controlled crude oil.

Primary Stocks of Refined Petroleum Products
Stocks held at refineries, bulk terminals, and pipelines. They do not include stocks held in secondary storage facilities, such as those held by jobbers, dealers, independent marketers, and consumers.

Refiner Acquisition Cost
The cost to the refiner, including transportation and fees, of crude petroleum. The composite cost is the average of domestic and imported crude costs and represents the amount of crude cost which refiners may pass on to their customers.

Released Oil
That portion of the base production control level for a property which is equal to the volume of new oil produced in that month and which may be sold above the ceiling price. The amount of released oil may not exceed the base production control level for that property.

Residual Fuel Oil
The heavier oils that remain after the distillate fuel oils and lighter hydrocarbons are boiled off in refinery operations. Included are products known as ASTM grades Nos. 5 and 6 oil, heavy diesel oil, Navy Special Oil, Bunker C oil, and acid sludge and pitch used as refiner fuels. Residual fuel oil is used for the production of electric power, for heating, and for various industrial purposes.

Rotary Rig
Machine used for drilling wells that employs a rotating tube attached to a bit for boring holes through rock.

Separative Work Unit (SWU)
The measure of work required to produce enriched uranium from natural uranium. Enrichment plants separate natural uranium feed material into two groups, an enriched product group with a higher percentage of U-235 than the feed material and a depleted tails group with a lower percentage of U-235 than the feed material. To produce 1 kilogram of enriched uranium containing 2.8 percent U-235, and a depleted tails assay containing 0.3 percent U-235, it requires 6 kilograms of natural uranium feed and 3 kilograms of separative work units (3 SWU).

Stripper Well Lease
A property of which the average daily production of crude petroleum and petroleum condensates, including natural gas liquids, per well did not exceed 10 barrels per day during the preceding calendar month.

Total Refined Petroleum Products Imports
Imports of motor gasoline, naphtha-type jet fuel, kerosine-type jet fuel, liquified petroleum gases, kerosine, distillate fuel oil, residual fuel oil, petrochemical feedstocks, special naphthas, lubricants, waxes, and asphalt. Imports of bonded bunkers, jet fuel, distillate and residual fuel oils for onshore military use, and receipts from Puerto Rico, the Virgin Islands, and Guam are based on data reported to the Oil Import Administration of FEA. All other figures are compiled by Bureau of Mines from Department of Commerce data.

Well
Hole drilled for the purpose of finding or producing crude oil or natural gas or providing services related to the production of crude oil or natural gas. Wells are classified as oil wells, gas wells, dry holes, stratigraphic tests, or service wells. This is a standard definition of the American Petroleum Institute.

Explanatory Notes

1. The two constituents of the atomic nucleus are protons and neutrons. The number of protons in a nucleus determines its chemical properties, and the sum of the protons and neutrons determines the weight of the nucleus. Protons and neutrons have approximately equal weights. The proton is electrically charged, while the neutron is electrically neutral.

Two nuclei with the same number of protons but different numbers of neutrons are said to be isotopes of the same element. Some combinations of protons and neutrons form stable (non-radioactive) nuclei. Radioactive decay occurs in nuclei which do not have a stable proton-to-neutron ratio. The half-life of a radioactive isotope is a measure of the rate of its decay. After a time duration equal to one half-life, only half of the original radioactive nuclei in a given sample remains. After another half-life, only half of the remaining half (one-fourth of the original nuclei) is left, and so on.

2. Hydrogen in nature consists of two stable isotopes. The predominant isotope has one proton and no neutrons in its nucleus. The isotope with a neutron in addition to the proton is called deuterium, or heavy hydrogen, and comprises only 0.015 percent of hydrogen in nature. Water in which all the hydrogen atoms are deuterium is called heavy water.

3. Quantities of uranium are measured by various units at different stages in the fuel cycle. At the mill, quantities are usually expressed as pounds or short tons of U_3O_8. After the conversion stage, the units of measure are either metric tons (MT) of UF_6 or metric tons of uranium (MTU). The latter designation expresses only the elemental uranium content of UF_6.

Following the enrichment stage, the same units are used, but the U-235 content has been enhanced at the expense of loss of material. At the fabrication stage, UF_6 is changed to UO_2, and the standard unit of measure is the MTU. We have chosen to present all uranium quantities as MTU; conversion factors to other units are given in the section on Units of Measure.

4. The units used to describe power generation at nuclear plants are all based on the watt, which is a unit of power. (Power is energy produced per unit of time.) As with fossil-fueled plants, nuclear plants have three design power ratings. The thermal rating (expressed in thermal megawatts) is the rate of heat production by the reactor core. The gross electrical rating (expressed in electrical megawatts, MWe) is the generator capacity at the stated thermal rating of the plant. The net electrical rating (also expressed in MWe) is the power available as input to the electrical grid after subtracting the power needed to operate the plant. (A typical nuclear plant needs 5 percent of its generated electricity for its own operation.)

The electrical energy produced by a plant is expressed either as megawatt hours (MWhe) or kilowatt hours (KWhe). Tables in the nuclear section show generated electricity as average electrical power. This enables a more direct comparison to design capacity and to previous months' performances. To obtain the quantity of electricity generated during a given time period (in megawatt hours), multiply the average power level (in megawatts) by the number of hours during that period.

The energy extracted from uranium fuel is expressed as thermal megawatt days per metric ton of uranium (MWD/MTU). The production of plutonium in the fuel rods is expressed as kilograms of plutonium per metric ton of discharged uranium (kg/MTU).

5. Uranium in nature consists of two isotopes, U-235 and U-238. U-235 comprises 0.7 percent of natural uranium. Its atomic weight, 235, is the sum of its 92 protons and 143 neutrons. U-238 comprises 99.3 percent of natural uranium, and its nucleus contains 92 protons and 146 neutrons. This small difference in atomic weight between uranium isotopes causes considerable differences in their nuclear characteristics. U-235 is fissile (fissionable), whereas U-238 is not. When U-238 is bombarded by neutrons, it captures a neutron rather than fissioning, and forms U-239. After two radioactive decays, U-239 becomes a fissile isotope of plutonium, Pu-239.

6. Domestic production of energy includes production of crude oil and lease condensate, natural gas (wet), and coal (anthracite, bituminous, and lignite), as well as electricity output from hydroelectric and nuclear powerplants and industrial hydroelectric power production. The volumetric data were converted to approximate heat contents (Btu-values) of the various energy sources using conversion factors listed in the Units of Measure.

7. Domestic consumption of energy includes domestic demand for refined petroleum products, consumption of coal (anthracite, bituminous, and lignite) and natural gas (dry), electricity output from hydroelectric and nuclear powerplants, industrial hydroelectric power production, and imports of electric power. Approximate heat contents (Btu-values) were derived using conversion factors listed in the Units of Measure. Electricity imports were converted using the Btu-content of hydroelectric power. 1975 electricity imports were estimated on the basis of imports levels during 1974.

8. Graphic presentations of petroleum volumetric data show Bureau of Mines (BOM) figures for 1973 through December 1974 and FEA figures for January 1975 forward. FEA monthly data are based on the *Weekly Petroleum Statistics Report* which presents volumetric data on domestic petroleum receipts and imports for all refiners and bulk terminal operators, as well as production and stock levels for each major petroleum product.

Conceptually, the major difference between FEA and BOM data occurs in the "Stocks" series. Stock levels reported by FEA for the major petroleum products are higher than those reported by BOM, because the FEA series includes stocks of independent terminal operators not counted by BOM.

In the current issue, cumulative 1972 and 1973 petroleum data presented in the text are based on BOM figures. Discussions of cumulative 1974 data are based on BOM figures for the first 11 months and FEA figures for the last month of the year.

9. Oil heating degree-days relate demand for distillate heating fuel to outdoor air temperature. Heating degree-days are defined as deviations of the mean daily temperature at a sampling station below a base temperature equal to 65°F by convention. Numerous studies have shown that when the outside temperature is 65°, most buildings can maintain an indoor air temperature of 70° without the use of heating fuels.

Mean daily temperature information is forwarded to the National Oceanic and Atmospheric Administration, Department of Commerce, from approximately 200 weather stations around the country. These data are used to calculate statewide heating degree-day averages based on population. The population-weighted State figures are aggregated into Petroleum Administration for Defense Districts and the national average, using a weighting scheme based on each State's consumption of distillate fuel oil per degree-day (1972 data base).

10. Domestic demand figures for natural gas liquids (NGL) as reported by BOM and reproduced in this volume do not include amounts utilized at refineries for blending purposes in the production of finished products, principally gasoline. Consumption of NGL at refineries for this purpose has remained at a fairly constant level since 1972 of around 700,000 850,000 barrels per day. NGL domestic demand statistics do incorporate, however, some liquefied gases produced at refineries (LRG) which are used for fuel and petrochemical feedstocks. The NGL production and stock series reported in this volume include only those liquids obtained from or held as stocks at natural gas processing plants and do not incorporate minor quantities of these liquids produced and/or held as stocks at refineries.

11. Bituminous coal and lignite consumption data reported by the Bureau of Mines are derived from information provided by the Federal Power Commission, Department of Commerce, and reports from selected manufacturing industries and retailers. Domestic consumption data in this series, therefore, approximate actual consumption. This is in contrast to domestic demand reported for petroleum products, which is a calculated value representing total disappearance from primary supplies.

12. Bituminous coal and lignite production is calculated from the number of railroad cars loaded at mines, based on the assumption that approximately 60 percent of the coal produced is transported by rail. Production data are estimated by the Bureau of Mines from Association of American Railroads reports of carloadings.

13. Mileage estimates for 1974 and 1975 were derived by multiplying the monthly seismic crew counts by the average number of miles traversed per crew month in 1973.

14. Prior to January 1975, diesel fuel prices were obtained from retail gasoline dealers that also sold diesel fuel. Beginning in January 1975, the diesel fuel survey was expanded to include selected truck stops plus additional retail gasoline dealers that sold diesel fuel. Consequently, diesel fuel prices for January 1975 forward are not exactly comparable to prior data. Selling price estimates are based on a survey of 31 cities. Margins are based on a survey of 10 cities.

15. The refiner acquisition cost of imported crude petroleum is the average landed cost of imported crude petroleum to the refiner and represents the amount which may be passed on to the consumer. The estimated landed cost of imported crude petroleum from selected countries does not represent the total cost of all imported crude. Imported crude costs to U.S. company-owned refineries in the Caribbean are not included in the landed cost, and costs of crude petroleum from countries which export only small amounts to the U.S. are also excluded.

16. The weighted average utility fuel cost for the total United States includes distillate fuel oil consumed by utilities whereas the regional breakdown for residual fuel oil prices represents only No. 6 fuel oil prices.

Units of Measure

Weight

1 metric ton	*contains*	1.102 short tons

Conversion Factors for Crude Oil
Average gravity

1 barrel (42 gallons)	*weighs*	0.136 metric tons (0.150 short tons)
1 metric ton	*contains*	7.33 barrels
1 short ton	*contains*	6.65 barrels

Conversion Factors for Uranium

1 short ton (U_3O_8)	*contains*	0.769 metric tons of uranium
1 short ton (UF_6)	*contains*	0.613 metric tons of uranium
1 metric ton (UF_6)	*contains*	0.676 metric tons of uranium

Approximate Heat Content of Various Fuels

Petroleum	
Crude oil	5.800 million Btu/barrel
Refined products, average	5.517 million Btu/barrel
Gasoline	5.248 million Btu/barrel
Jet fuel, average	5.592 million Btu/barrel
Naphtha-type	5.355 million Btu/barrel
Kerosine-type	5.670 million Btu/barrel
Distillate fuel oil	5.825 million Btu/barrel
Residual fuel oil	6.287 million Btu/barrel
Natural gas liquids	4.031 million Btu/barrel
Natural gas	
Wet	1,093 Btu/cubic foot
Dry	1,021 Btu/cubic foot
Coal	
Bituminous and lignite	
Production	24.01 million Btu/short ton
Consumption	23.65 million Btu/short ton
Anthracite	25.40 million Btu/short ton

Electricity Conversion Heat Rates

Fossil fuel steam-electric	
Coal	10,176 Btu/kilowatt hour
Gas	10,733 Btu/kilowatt hour
Oil	10,826 Btu/kilowatt hour
Nuclear steam-electric	10,660 Btu/kilowatt hour
Hydroelectric	10,379 Btu/kilowatt hour
Electricity Consumption	3,412 Btu/kilowatt hour

U.S. DEPARTMENT OF COMMERCE
National Technical Information Service
Springfield, Va. 22161

OFFICIAL BUSINESS

PRINTED MATTER

AN EQUAL OPPORTUNITY EMPLOYER

POSTAGE AND FEES PAID
U.S. DEPARTMENT OF COMMERCE
COM-211

U.S. MAIL

Federal Energy Administration
Monthly Energy Review

AMERICAN REVOLUTION BICENTENNIAL 1776-1976

C

BACKGROUND PAPER ON ENERGY CONSERVATION

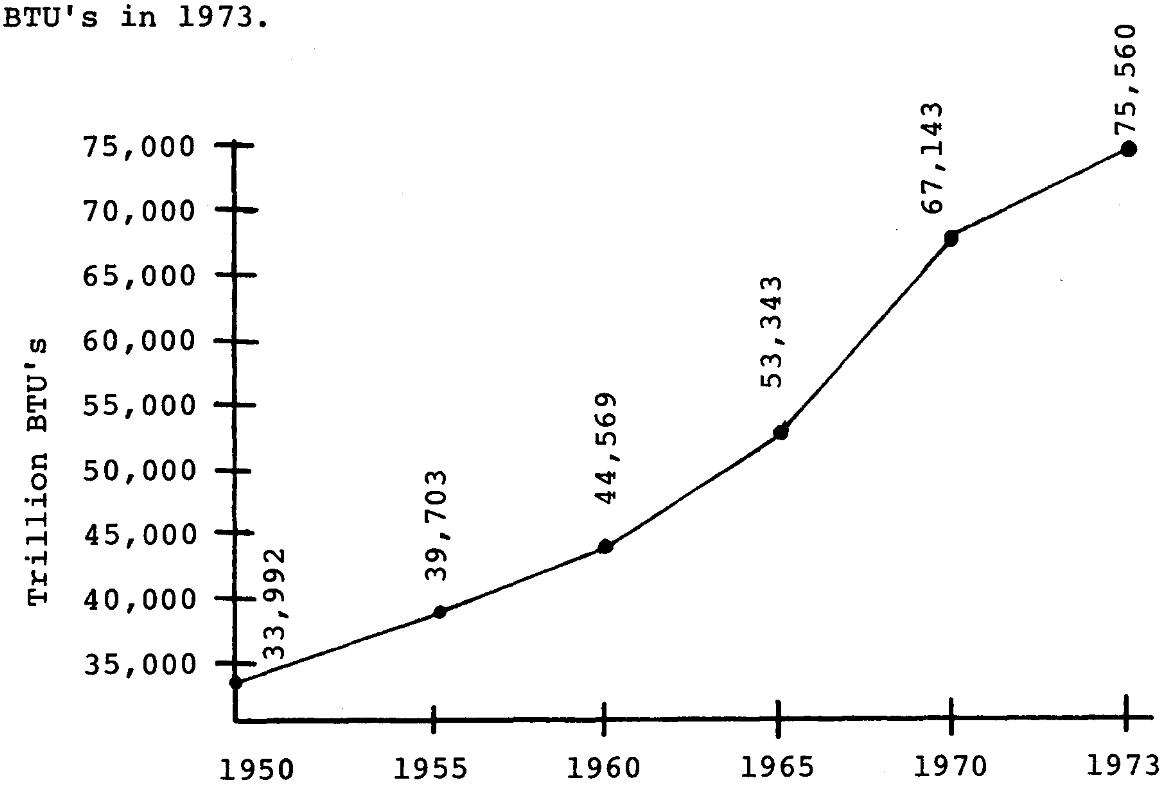
The purpose of this paper is to provide background material to assist in understanding and discussions of the role Federal energy conservation efforts can play in a developing national energy policy. The paper covers:

- -- history and analysis of energy consumption in the United States
- -- brief comparisons of U.S. energy consumption with other developed countries
- -- the role of energy conservation efforts vis-a-vis the marketplace

U.S. ENERGY CONSUMPTION: AN HISTORICAL PATTERN

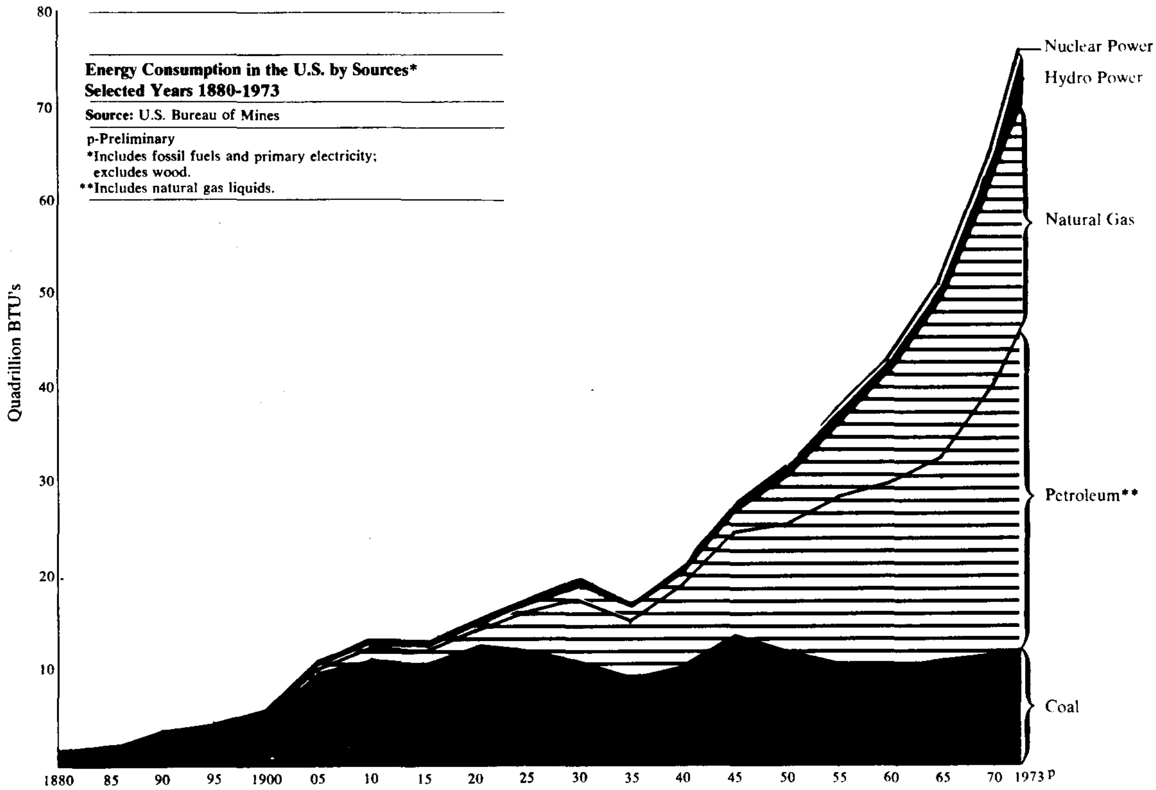
Energy consumption in the United States has been a pattern of unrestrained usage for almost a century. Until 1950, our consumption rose at a fairly steady pace; but in the last 25 years, our total energy use has more than doubled.

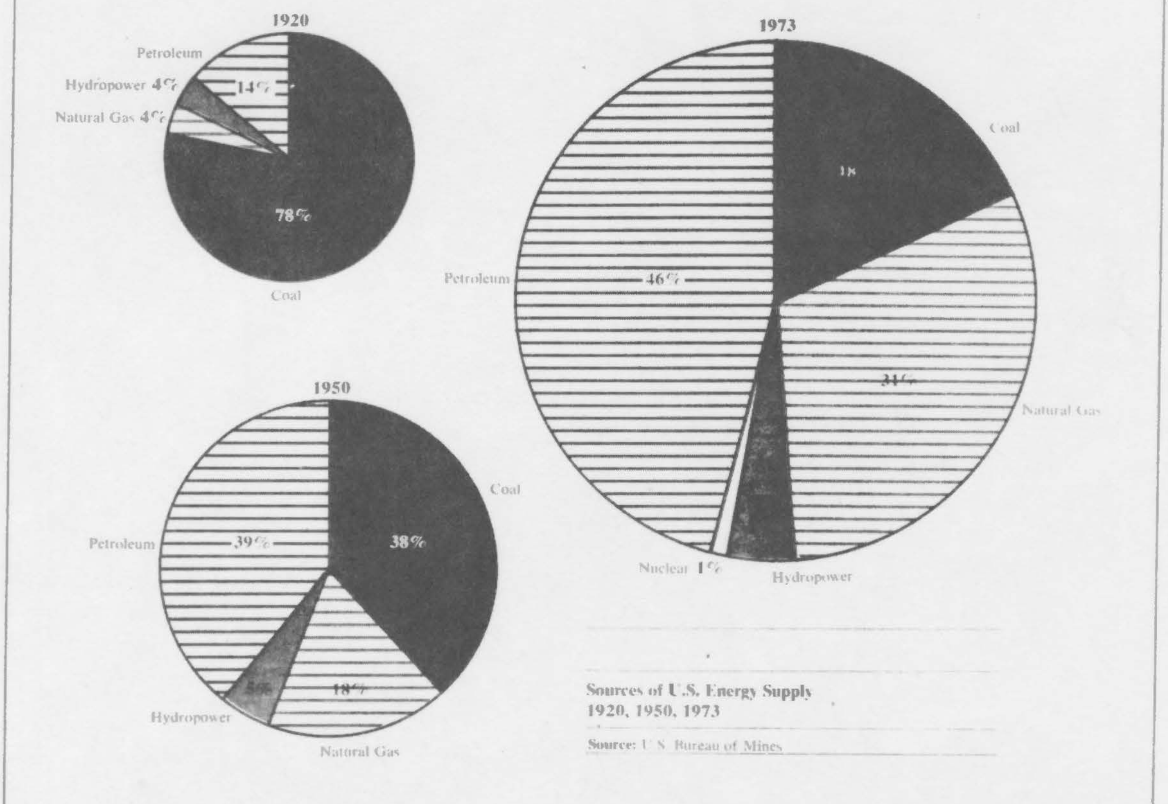
Consumption increased at an average annual growth rate of 3.5 percent between 1950 and 1965, rising from less than 34,000 trillion BTU's to over 53,000 trillion BTU's. After 1965 demand increased at a rate of 4.5 percent annually, reaching a total consumption level of over 75,500 trillion BTU's in 1973.



We can look at our energy consumption pattern in two ways: by source and by end use.

About 85 percent of the annual increase in consumption since 1940 has been in oil and natural gas. These two fossil fuels have continually supplied a greater percentage of the Nation's total consumption. By 1950 they accounted for 39 percent and 18 percent respectively of the U.S. supply; in 1973 they provised 46 percent and 31 percent--over three-fourths of our total U.S. energy supply--as is shown by the two charts following.





Sources of U.S. Energy Supply
1920, 1950, 1973

Source: U.S. Bureau of Mines

We can divide the end-uses of energy into three main sectors: industrial, transportation, and buildings.

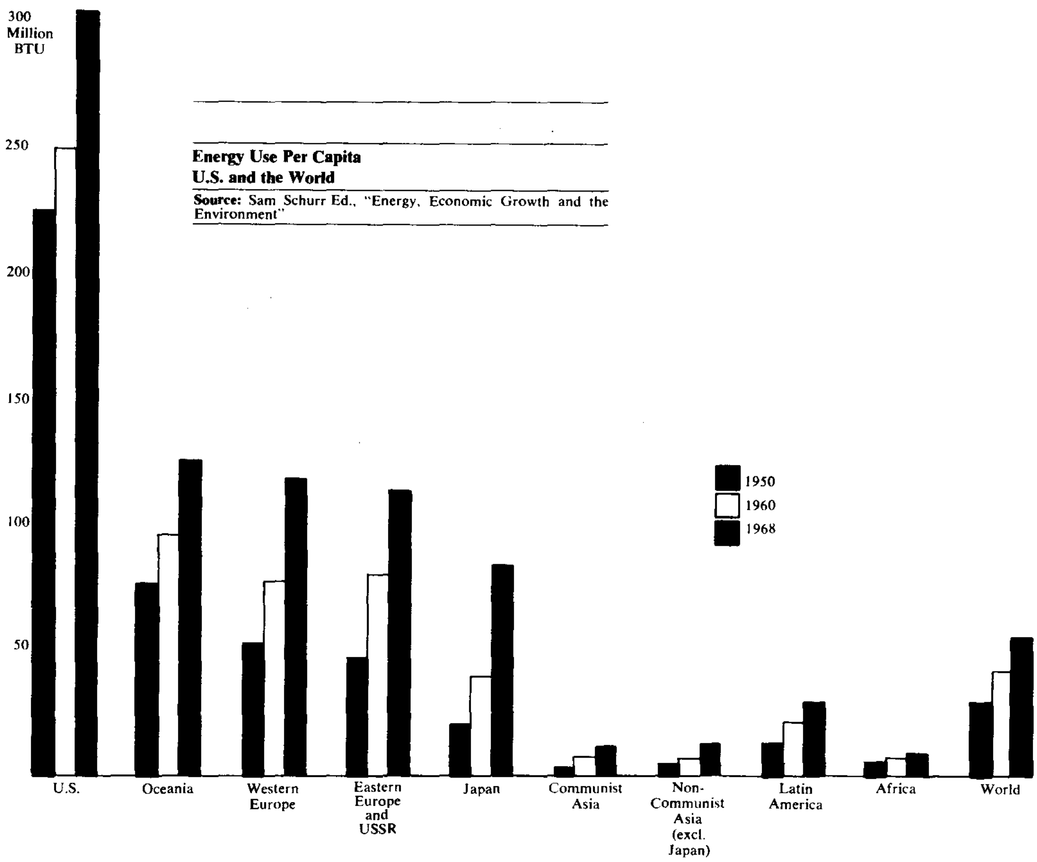
The industrial sector accounts for about 40 percent of total U.S. energy consumption. In 1972, American industries consumed 30,000 trillion BTU's of fuels, about half of which went for heating processes. In this sector, we find that the 10 most energy intensive industry groups consume about 56 percent of the sector total.

The transportation sector accounts for 25 percent of total U.S. energy consumption and about 60 percent of U.S. petroleum consumption. Motor vehicles consume about 77 percent of transportation energy or almost one-fifth of all U.S. energy demand.

Buildings use almost one-third of U.S. energy. This sector's energy demand was growing at about four percent per year before the embargo--in effect doubling every 19 years. In 1974, there were approximately 72 million occupied housing units and 24 billion square feet of commercial space. Of total energy use in the buildings sector, 70 percent is consumed in residential structures and 30 percent in commercial structures. Primary uses within this sector include space heating and cooling (57 percent), operating equipment and appliances (33 percent), and lighting (10 percent).

U.S. ENERGY CONSUMPTION: COMPARED TO OTHER COUNTRIES

The United States, with about six percent of the world population, consumes about 30 percent of its energy. That consumption is most graphically illustrated by examining per capita energy consumption in the table below.



A common reaction to this display is that energy consumption must obviously be tied into a country's standard of living. Yet review of the per capita energy consumption of the most developed countries reveals that, for example, Sweden, West Germany, and Denmark have approximately the same standards of living while consuming roughly one-half the energy--on a per capita basis--of the United States.

Comparison of Per Capita GNP and Energy Consumption

	GNP Per Capita	Energy Consumption Per Capita (Gallons of Oil Equivalent)
Sweden	6,000 ('73)	1,467
West Germany	5,613 ('73)	1,080
Denmark	6,000 ('73)	1,059
United States	5,515 ('72)	2,460

This analysis only shows the nature of the long term opportunity. Surely no one would suggest that the United States can immediately and easily obtain reduced per capita consumption. But at least one can begin to realize that the potential exists for substantial efficiency increases.

CONSERVATION: A PERSPECTIVE ON ITS ROLE

The Arab oil embargo, the high price of imported oil, and the threat of future supply interruptions have resulted in a wide range of suggestions for reducing energy consumption. By "conserving" we can reduce our dependence on foreign oil imports, reduce energy costs, and improve our balance of payments, but at the same time, we realize that the use of energy is critical to our prosperity and that an arbitrary drastic reduction in energy use would produce a significant reduction in our national wealth and welfare. Therefore, the basic question is not whether we should "conserve" energy, but how we should "conserve" it and how much we should "conserve." The answers to these questions are in turn part of the larger issue of efficient resource allocation.

Energy conservation should be evaluated with respect to the efficient use of all scarce resources including scarce energy resources, but not exclusively in terms of energy savings alone. A benefit-cost framework provides for the comparison of the value of benefits from energy conservation with its costs, and unless the benefits outweigh the costs, such conservation is not consistent with efficient resource use. If, however, the benefits from conservation exceed costs, such conservation will improve resource allocation and increase the total value of national production.

This approach to energy conservation shows that the beneficial effects of energy conservation go far beyond what is measured by the reduction in the amount of energy consumed and that the benefits from conservation exceed the market value of the energy saved. Further, in the very important case where fuels or energy are underpriced, government programs to promote energy conservation can play a critical role in improving the efficient use of energy. Such programs can be an essential element in getting public and political acceptance of a more rational price structure for energy. In short, energy conservation can play a major role in bringing improvements in the nation's energy/economic picture by improving efficiency; and conservation is more than simply reducing energy use.

By approaching energy conservation in terms of a more efficient use of our energy resources, we get the concept of conservation off the horns of the telling criticism that just cutting back on energy use for its own sake, and the more the better, is likely to produce severe adverse economic effects. The benefit-cost approach provides a way of distinguishing conservation which is economically beneficial from that which is economically harmful. It also provides a way of measuring the degree to which types of conservation are beneficial or harmful. From an economic standpoint, a quad saved is not just a quad saved; we have to find out where and how it was saved and with what effect.

CONSERVATION PROGRAMS AND THE USE OF THE MARKETPLACE

While economists agree that many markets in the economy are not perfectly competitive for any number of reasons, it is still helpful to use the competitive ideal as a point of departure. By identifying where and why energy markets fail to allocate resources efficiently, we can identify possible areas where conservation may improve efficiency. We can estimate benefits and costs by using estimates of what the competitive price would be.

To illustrate this last point, consider the case of regulated natural gas where the regulated price is considerably below what the competitive market price would be. The non-regulated intrastate price, for example, is mugh higher than the regulated interstate price, and some customers in the interstate market cannot get all the gas they would like to have at the regulated price. At the same time, those consumers who can get gas at regulated prices find it profitable to use gas in ways that are inefficient from a national viewpoint. The reason is that the price they pay does not represent the full value of a unit of natural gas in some alternative use. Therefore, the consumers of natural gas will use it where either other fuels should be substituted or energy conserving technologies should be adopted. This does not occur because the low price of gas does not make it profitable to the particular individual or the firm. The importance of this point becomes apparent when we discuss energy conservation measures, such as insulating buildings, that could produce a substantial savings of natural gas.

One of the most important reasons that energy resources are not being efficiently used is the one just discussed, namely that some forms of energy are priced below their true marginal value. The regulated price of interstate natural gas, the regulated price of "old oil," and low electric power rates such as those of TVA and other federally owned projects are significant cases in point. Other reasons why energy prices may not reflect the true value of energy, and consequently the true cost of using it, are: (1) monopolistic elements in the energy industry; (2) special tax treatment given the energy producing firms, such as the recently repealed oil depletion allowance; and (3) externalities such as effects on the environment. Perhaps the most important external cost of energy use that enters current policy discussion is that of dependence on foreign imports.

In the case of incorrect pricing, what is cost effective from the individual user's point of view is not cost effective from a national point of view. With rare exceptions, individual users will only conserve when the benefits to them exceed their costs. They will not consider the value of the scarce energy resource in some alternative use. Therefore, if natural gas is significantly underpriced, the demand and use of natural gas will be too great from a national point of view, but not from the point of view of an individual user. Given the price, the user will conserve only if the government intervenes and provides an incentive. In cases where energy is underpriced the optimal amount of conservation can be achieved only through some form of government action.

There are a number of other reasons why, even if energy were correctly priced, individuals and firms do not pursue energy conservation to optimal levels. One stems from ignorance or lack of information on the part of the consumers. A homeowner who is considering insulating his house may have very little information about potential benefits in terms of reduced heating and air conditioning costs, and therefore he would not know that it is cost-effective. Another problem is financing energy conservation. Firms and households have limited capacity to borrow, and it may not be possible or prudent for them to increase their indebtedness to obtain the finances required to put in energy conserving improvements.

Both of these situations lead to what is referred to as the first cost bias with regard to buildings and durable goods. Because the consumer does not realize the energy savings that can be gained from energy conservation and because he may have difficulty arranging the financing, he may not be willing to pay the additional cost for a building or an appliance that will yield an unknown stream of future benefits in terms of reduced operating costs. Not only may the benefits not be obvious, but the increased initial cost may create a financing problem. Moreover, builders and appliance manufacturers do not incorporate costly energy saving features unless the consumer is willing to pay extra initial cost.

An additional risk associated with investment in energy conserving technologies and devices results from uncertainty about the future price of energy. If, for example, energy prices were to fall from their current levels to their pre-embargo levels, much of the cost-effective energy conservation based on current prices would not be cost-effective given the old prices. This adds uncertainty about the benefits from energy conservation in terms of future savings, and this risk creates an additional barrier to investments in energy conservation.

Finally, there is basic inertia with respect to adopting new energy-saving devices even when price changes have made them cost-effective. Part of this inertia is associated with problems of information, financing, and risk. However, in addition, individuals and corporate management have limited time and energy and it may be some time before they take advantage of new investment opportunities. An investment in energy conservation is just one of the many possibilities that a firm or individual has to consider.

To the extent that government action can speed the adoption of energy conserving investments with positive net benefits, this action is producing benefits over and above what would be obtained if the process were left to market forces alone. The reason for this is the time value of money. A dollar of benefits today is worth more than a dollar of benefits a year hence, so if government action can speed the adoption of energy conservation, and thereby obtain future benefits sooner, a net increase in benefits can be attributed to the government's program.

D

DRAFT PRELIMINARY EVALUATION OF MEMBER COUNTRY CONSERVATION PROGRAMS

SUMMARY REPORT OF THE CHAIRMAN OF THE INTERNATIONAL ENERGY AGENCY SUBGROUP ON CONSERVATION

This is a draft summary of the conservation program evaluations prepared at the last meeting of the Subgroup on Conservation, April 14, 15, and 16 in Paris. This report should be considered very preliminary.

Over the next two months, the data submitted by each country will be updated and newly adopted programs will be incorporated. It should be noted that this evaluation is based primarily on the programs that have been adopted and put in place by member countries. Those programs and policies still under consideration or study have been given much less weight.

The review shows that there are considerable differences in the quality of conservation programs adopted by member countries. Not all programs are of equal impact and countries are not yet sharing the conservation responsibility evenly.

In addition, every program still has room for improvement. Even the better programs have gaps or lack meaningful action in certain areas. Hence, the combined IEA long-term program, which is the sum of the member country efforts, falls short of its potential.

A narrative summary evaluation of each country's program is presented below with the strongest programs listed first. Each summary is followed by figures which show the relationship of imported oil to total energy consumed for that country in 1975 and projected for 1985. IEA averages for these percentages are:

	1975	1985
Imported Oil/Total Energy	53%	47%

United Kingdom

Clearly the United Kingdom has one of the best conservation programs in the IEA at the present time. Energy fuel prices had been controlled at levels below world market levels. This policy has been reversed. In addition, taxes have been introduced that add 25% to the cost of gasoline; electricity prices have been revised to bear more heavily on larger consumers than smaller ones. The program also includes compulsory reduced heating levels for all non-residential buildings, loans to industry for energy savings investments, new building standards for new homes that double insulation requirements, a change in insulation tax allowance for industry from 40% to 100%, restrictions on the daytime use of electricity for external display and advertising and introduction of major publicity campaign (£ 3 million).

Recommendations for possible program improvements include establishing a public national savings target, developing programs to utilize waste heat from electrical power plants, considering pricing incentives/disincentives to discourage autos in urban areas and adopting possible incentives for insulating existing homes.

	1975	1985
Imported Oil/Total Energy	42%	13%

Denmark

The Danish program is still being developed with a law passing through Parliament that will introduce major changes in the buildings sector where 50% of Denmark's energy is used. With passage of the law, Denmark will have possibly the strongest program in the IEA. Measures already adopted include a publicity campaign (2 million K--$400,000), a heating consultative service for homeowners, rent controls amended permitting increases to cover costs of improving heating systems, landlord mandatory investment funds released for use in installing insulation, increased taxes on electricity raising prices by 20%, electrical rates doubled for big consumers and raised very little for small consumers, loan program to hothouse growers adopted to improve heat consuming systems, autos limited in some city centers, bus rates around Copenhagen reduced, octane rating of gasoline reduced from 100° to 99°, fixed hour intercity passenger railroads introduced between Copenhagen and major towns, loan program for industrial energy saving projects introduced (10 million K--$2 million). In addition, Denmark has one of the finest district heating systems in the world with one-third of the heat produced from power plant waste heat, their gasoline price is about 2.50 Kr per liter ($1.90 per gallon or a tax above cost of $1.20-$1.30), and autos are taxed according to vehicle weight.

The program needs stronger measures in the buildings sector such as additional incentives for improving existing buildings and more stringent thermal standards for new residential and commercial buildings. These are in a proposed law currently under consideration (new law would improve insulation and ventilation standards by 50%). In addition, some consideration might be given to stronger measures for industry even though only 20% of Denmark's energy is used in that sector.

	1975	1985
Imported Oil/Total Energy	87%	82%

Ireland

The Irish program is one of the better ones in the IEA although it may not be as comprehensive as that of the United Kingdom or Denmark. There is no subsidization of fuel prices and taxation on gasoline has been increased to raise the price by 30%. Electricity rates are being revised over time to reflect marginal production costs (although there is some question as to whether rates are subsidizing large inefficient users), new thermal building codes are being put in place, a very effective publicity campaign is being implemented and grants are being given to new and existing industry contingent on meeting good conservation standards.

The program has no measures aimed at the transportation sector (where 25% of Ireland's energy is used) except mandatory speed limits. The program also lacks any full time conservation staff to develop objectives or collect and analyze data. Finally, there does not appear to be any incentive to improve the thermal efficiency of existing residences or of new home appliances.

	1975	1985
Imported Oil/Total Energy	81%	64%

Spain

The Spanish program is difficult to evaluate. It has a goal of reducing dependency on foreign oil from 76% to 45% in 1985, but plans to increase absolute consumption of foreign oil by 40% during that time. The program rations electricity to homes and industry at 90% of 1973 levels and of fuel oil to homes (80% of 1973) and industry (90% of 1973).

At the same time, it should be noted that prices for these energy sources have been increased dramtically, more than offsetting the world crude price increase. Those who desire to exceed the rationed level must pay a 25% tax on the additional amount. Also included in the program are mandatory insulation standards for all new buildings, a mandatory 20% reduction in the number of airline flights, restriction of entertainment hours, mandatory heating levels for public buildings, a form of daylight-savings time, and a sizeable public campaign.

The program appears weakest in the transportation area where gasoline price increases have been partically offset by decreases in taxes and where highway construction continues to be emphasized. There is also no incentives or program for ensuring the insulation of existing buildings although this problem is under study as is a program to develop a cadre of building auditors.

	1975	1985
Imported Oil/Total Energy	63	42

Italy

The final form of the Italian program is not yet apparent but a number of measures have already been adopted that make it a noteworthy program. Italy has adopted a progressive (inverted) rate structure for electricity in the residential and commercial sector. They have also raised an already high gasoline tax by 50% (tax increased price by 29%). All other other oil products are priced at world market levels. Although the industrial sector program is still under development, a system for controlling burners has been implemented.

Twenty percent of Italy's fuel is used in the transportation sector and even though the country has the highest auto efficiency average in Europe, it is believed that some conservation actions should be targeted on that sector. In addition, the country may consider stronger measures for industry, measures to encourage thermal improvements in new and existing residences, adopting a publicity campaign and creating a permanent government organization to lead the conservation effort.

	1975	1985
Imported Oil/Total Energy	69%	54%

Japan

The Japanese program ranks in the top 6 among currently implemented IEA programs. The program includes a strong industrial emphasis with negotiated energy efficiency goals between government and industry, a tax measure that allows a 33% first year write-off of industrial energy saving investments and subsidized development loans provided for energy conservation improvements. In the electricity sector the previous tariff structure favoring large consumers has been changed into a system with progressive rates, including for households, an increase of 20% for consumption exceeding 120 kwh per month and a further increase of 10% above 200 kwh per month. For industrial customers, tariff now includes a 20% increase for consumption exceeding April 1974 demand levels. All fuels are priced consistent with world market prices and gasoline taxes have been increased to add another 5% to the total gasoline price. In addition, over 24 million dollars is being allocated for energy conservation R&D.

The program is weakest in the transportation and buildings areas where only voluntary measures are now being pursued, except for an 80 kwh speed limit. There is no strong measure in force to shift transportation away from road traffic to more efficient modes. In addition even though very little energy is currently used in residential and commercial buildings, no significant measures have been adopted to ensure efficient use in these sectors as the economy grows.

	1975	1985
Imported Oil/Total Energy	79%	70%

Sweden

By mid-year Sweden will undoubtedly have one of the three best energy conservation programs in the IEA. However, until it is officially adopted by the Parliament (nearly assured within a few months) the program cannot be so considered. Until the program is adopted, the country has only its already existing high taxes on gasoline ($.72) and already stringent building codes. The new program being adopted includes a goal of reducing energy growth from its present 4 1/2% to 2% from now to 1985, and to zero growth from 1990 onwards. The measures include government financial support for insulating existing and new buildings (through loans and grants), energy conserving industrial processes (up to 35% of cost) and energy saving appliances. New taxes on electricity and gasoline will raise prices 10% and 5% respectively. In addition, it includes new, even more stringent standards for planning and constructing new buildings and government regulations of energy intensive industries through control of expansion.

The major question is whether the program as presented will actually meet the very laudable goals set forth. The weakest part of the program appears to be the transportation area where few strong measures are to be implemented.

	1975	1985
Imported Oil/Total Energy	76%	66%

Germany

The German program lacks the intensity and comprehension of some of the IEA programs but there are some measures under study that could help. The program adopted includes significant budget for conservation R&D, a tax on fuel oil (which was to have been dropped) has been prolonged, a 7.5% investment tax credit for construction of refuse burning power stations, refuse burning heating plants, heat pumping stations and heat distribution plants. An accelerated development of district heating plants is also planned. About half the price of gasoline is tax and there is an excise tax on autos that varies with engine size although both these measures were adopted prior to January 1974. Heat pumps installed by industry can be subsidized if there is a positive conservation result.

The program can be improved considerably with the adoption of stringent new thermal standards for new and existing buildings and appliances now under consideration. New measures should also be considered in the transportation sector, including speed limits, and industry where there are no major conservation measures currently under consideration.

	1975	1985
Imported Oil/Total Energy	49%	43%

Belgium

Belgium estimates its oil consumption in 1985 to be 28. mtoe compared with 27.4 in 1973. This represents a reduction in the petroleum share of Total Primary Energy from 58% to 42%. The program to achieve these targets does not appear to be fully developed. The program does include government grants (to to 25% of cost) for improving the thermal efficiency of existing buildings, speed limits and severe penalties for speed offenses, graduated tax on engine capacity, preferential tax rates to encourage diesel engines, less regressive (flatter) electrical rates, and a program to require furnace burner check-ups in commercial buildings.

The program does not include appliance labeling or standards, mandatory thermal standards for new residential and commercial buildings or incentives for industry to conserve, although these are under consideration. The program appears weakest in measures to reduce consumption in industry. In addition, consideration should be given to actions to shift from autos to more efficient transportation and to create an organization to focus on energy conservation policies and programs.

	1975	1985
Imported Oil/Total Energy	51%	42%

Canada

The Canadian program is faced with the challenge of reversing the highly adverse trend of a very high and increasing level of consumption per capita. It is doubtful that the program adopted thus far will have a major positive effect. The program does include mandatory appliance labeling, new high insulation standards for residential construction, an expanded public education program, a permanent energy conservation staff and a move toward less regressive (flatter) electrical rates.

Unfortunately, the program is hampered considerably by petroleum prices controlled below world market levels. In addition, the program lacks any major incentive for industry to conserve, no auto efficiency standards, incentives to upgrade the efficiency of existing homes, program in waste management or strong measures to shift transportation from autos to more efficient modes. Further, the Federal nature of Canada's political system has caused difficulties since the authority for many actions is lodged at the Province level and these governments have been slow to respond to Federal initiatives.

	1975	1985
Imported Oil/Total Energy	2%	24%

Switzerland

The Swiss program lacks comprehensiveness but a few measures have been adopted and more appear on their way with the expected passage of the "Urgent Energy Law." Gasoline and fuel oil taxes have been increased raising the prices by 10% and 7%, respectively. Even higher increases are envisioned under the Urgent Energy Law. In addition, a public campaign has been implemented, private cars in certain center cities restricted, and the regulation to diminish the lead content in gasoline suspended.

No national measures, however, have been adopted to ensure that new and existing buildings are thermally efficient or that energy will be saved in industry or transportation.

	1975	1985
Imported Oil/Total Energy	72%	62%

Netherlands

The Dutch program is in the process of passing through Parliament. Even upon passage it does not appear that it will be one of IEA's stronger programs. The current program does include major government subsidies for encouraging insulation in existing buildings, energy standards for new buildings, a public campaign and voluntary programs to conserve in all sectors. Under consideration are several actions to make the program stronger, such as new taxes on gasoline, flattening of electrical rates, and appliance labeling.

The programs adopted and planned lack any aggressive measures aimed at conservation in industry and additional programs to increase efficiency in the transportation area.

	1975	1985
Imported Oil/Total Energy	34%	59%

United States

The American program must overcome an extremely high per capita historical energy consumption pattern and as such must be comprehensive and strong to be effective. At the present time, it is neither. The current program depends almost entirely on voluntary programs, research and development and public education. It does include a mandatory speed limit and a mandatory oil-to-coal conservation program. The Executive Branch has proposed a fairly comprehensive conservation program (although it focuses primarily on years 1975-1985 and would make few major structural changes necessary if the U.S. is to reduce consumption substantially in the long term) but the Congress does not appear to be receptive to such a program at this time.

A major deficiency of the current U.S. situation is that energy prices for oil and natural gas are controlled below world market levels. In addition, there is no incentive for improving the thermal efficiency of existing homes or the efficiency of appliances, no mandatory standards for new commercial and residential buildings, no incentives or aggressive program to improve energy efficiency in industry and encourage waste management, almost no taxes on gasoline or other energy products to curb usage, no incentives or standards to reduce auto miles traveled or improve auto efficiency. Electrical rates are generally regressive in that rates are lower as consumption increases and there is very little use of peak load pricing or other load management techniques common in some European countries. Finally, the program does not address itself to the existing inducements (e.g., tax deductions for interest on single family dwelling mortgages) that encourage construction of energy intensive dwelling units in land use patterns that prohibit energy efficient modes of transportation. Many of these deficiencies could be corrected by adoption of a program similar to that proposed by the Executive Branch, thus making the U.S. program one of the stronger in the IEA.

	1975	1985
Imported Oil/Total Energy	19%	18%

Austria

The Austrian program is quite weak and could be improved considerably. The only elements of the government's program already in force are an insulation subsidy scheme for new and existing buildings and an education campaign. It appears that fuel prices may not yet reflect full world market levels although they have been increased.

There is no conservation organization and only 1 or 2 people involved on a part-time basis with conservation problems. No substantial measures have been adopted for transportation, new or existing residential buildings or industry.

	1975	1985
Imported Oil/Total Energy	40%	41%

Norway

The Norwegian government has adopted a policy of reducing the energy growth rate from 4-5% per year to 3-3.5% between 1974 and 1980, however, no positive decisions regarding a conservation program have been forthcoming as yet. Hence, there are no substantial conservation measures in the industrial, buildings or transportation sectors. Data on current and projected consumption were not submitted.

Turkey

Turkey did not submit energy conservation programs for review, thus has not been evaluated during the preliminary examination.

New Zealand

New Zealand did not submit energy conservation programs for review, thus has not been evaluated during the preliminary examination.

E

F

MINIMUM SAFEGUARD PRICE

The IEA Governing Board's decision of March 20 defined as an objective the encouragement and safeguarding of investment in conventional alternative energy sources. It recognized that this objective would be at risk if imported oil were sold in IEA nations below a certain agreed price. The U.S. delegation to the IEA played a major role in fashioning the IEA position, since the U.S. had recognized the implications of the large differential between production costs of alternative sources in IEA nations and OPEC production costs. To protect U.S. investors from the risk of predatory pricing by OPEC nations, the President asked for standby authority to use tariffs, quotas or other means in Title IX of the Energy Development Security Act of 1975.

Because the minimum safeguard price has been agreed to in principle, key IEA (and U.S.) decisions center around the level of the price, the selection of an implementing mechanism, and the timing of efforts to seek specific agreement on these.

KEY ISSUES

I. Timing

The prospect of the July 1 IEA Governing Board action regarding the minimum safeguard price makes timing the most immediate policy question to be considered. The U.S. negotiating position must be resolved to decide whether during the June meetings of the IEA Governing Board we should strive for agreement on the price level (or range) and implementing mechanisms, or to defer settlement of the specifics and seek agreement on standby measures to be enacted by participating countries.

Deferral of the specifics would avoid choices made in a period of economic and energy policy uncertainty and would allow time for oil price trends to clarify. At the same time it would allow greater flexibility in negotiating with producer countries and would not place a floor under oil price negotiations with OPEC. Although under this negotiating stance, no specific protection price would be set, the prospect of protection for investors in energy resources would be established. In any case, since the price for "new" U.S. crude appears high enough to encourage new investment, the protection arguement for immedicacy does not seem to be strong. Politically, there has been negative Congressional reaction to a price floor concept, and arguing over a specific level or mechanism at this point may endanger cooperation on other issues.

A deferral policy would also permit individual countries to develop programs in response to domestic economic realities and priorities. In regard to the IEA as a whole, the resolution of technical issues in a "go slow" consensus manner might ultimately produce stronger agreement among the IEA nations. Furthermore, an activist stance on the part of the energy-rich U.S. might produce resistance from the energy-poor nations.

On the other hand, it can be fairly argued that failure to specify mechanisms and select a level immediately may weaken the IEA's position vis a vis the producer nations since no tangible evidence of consumer solidarity is provided. Also, the U.S. determination to develop alternative resources is not as strongly signaled to OPEC. A specific level articulated now would give investors a detailed idea of which investments will prove feasible in the long run. The acceptance of a minimum safeguard price might also provide OPEC nations with a long-term minimum price planning base, reduce uncertainty in the market, and thus help normalize producer-consumer relations. Further, given the high level of current world prices, agreement on the specifics might prove easier now than in a future in which prices may have declined. It should also be noted that since the U.S. has led the way on the minimum safeguard price concept, any reluctance to push ahead on specifics might raise doubts about U.S. credibility and seriousness of purpose in the IEA.

II. Price Level

FEA analysis has shown that a price in the vicinity of $7 (1973 dollars) would protect major sources of increased U.S. supply (Outer Continental Shelf and Alaska oil). Additionally, a price in this range would have a positive conservation effect, by setting an upper limit of U.S. demand at about 2.4 MMB/D by 1985 (PIR forecast). A much lower price would not serve the U.S. adequately as far as protecting major supplies (Prudhoe Bay, for example, comes on at $4.50/barrel; Lower 48 old field secondary recovery at $5.00). On the other hand, a high price would legitimize cartel price hikes and put the consuming nations in a contradictory position in negotiations with producers, especially on claims that high OPEC prices were damaging the economy.

III. Implementing Mechanism

Several mechanisms could be chosen to implement a minimum safeguard price: variable tariff, flat tariff, volumetric quota, state trading monopolies, or petroleum use tax. The variable tariff would seem the best mechanism for the reasons that follow. A flat tariff, the most recognized form of trade intervention, would only coincidentally maintain a minimum safeguard price unless the international price of petroleum were nearly constant (which is not the case). A volumetric quota requires accurate prediction of supply and demand unforseen events could cause it to miss minimum safeguard price levels. Additionally, the quota requires an allocation mechanism for import rights and a means of apportioning short-term shortages and may create windfall profits for domestic producers.

A state trading monopoly would work much like quantitative restrictions, if the assumption of its holding inventories is not allowed. The monopoly would forecast imports in the trading period at the minimum safeguard price level, and import only that amount. The obvious disadvantage is that the estimated level of imports might not guarantee the minimum safeguard price if there were shocks in the price-quantity forecasting system. Even the variable tariff is not without problems -- it is perhaps perilously close conceptually to the variable level which the U.S. has consistently opposed, and it could be complex administratively.

BACKGROUND

Reaction to the minimum safeguard price concept in Congress has been generally cool. The thrust of an OPEC price break in the near term has not garnered much public credibility, and there has been some feeling in Congress that the Administration does not currently have the authority to engage in IEA minimum safeguard price negotiations. At the same time, the argument exists that protection of domestic investment in alternative sources could be achieved through targeted deficiency payments. This method would shift the supply emphasis from an IEA cooperative mode to a more narrowly defined domestic supply strategy, but the latter ideology has its proponents in the Congress.

Title IX of the Administration's Energy Development Security Act is temporarily dormant. No hearings were scheduled by the committees to which the original bill was referred. Existing executive authority under Section 232 of the Trade Expansion Act of 1962 could be relied upon for negotiating authority. However, the Ullman bill would amend Section 232 to remove this flexibility, and S621 (passed by the Senate May 1, 1975) would effectively add a veto provision to the exercise of this authority for price floor purposes.

Within the Administration, the minimum safeguard price issue has not produced a unified stand. On the negative side one view is that while such a barrier might help insulate domestic producers, consumers would be insulated from certain beneficial effects of a downward price movement. Further, the wisdom of government entry into the international petroleum market is questioned given the general uncertainty of the market. The opposing view points to the positive effect of a "correctly set" price level on the development of alternative energy sources and on conservation. If the minimum safeguard price concept produces strong IEA consensus, OPEC may be confronted with an effective counterforce to the producer cartel. Also, it is noted that implementation of the concept does not necessarily require direct intervention in the world petroleum market.

In addition to the key issues discussed earlier, other difficult technical questions remain unresolved, including:

1. Design of safeguard prices for petroleum products
2. Impact of an SDR-denominated safeguard price on investment decisions in countries whose currencies undergo either a secular rise or a secular decline vis a vis the SDR.
3. The mechanics of complaint and enforcement, especially in the context of barter deals.
4. Duration of Agreement
5. Definition of "Imported Oil"
6. Definition of "price"
7. Provision for review of level and review interval

Although some of the technical issues bear on policy questions, they are probably not key decision variables. However, it should be noted that technical deliberations could be used as a means of pacing the IEA in movement toward major decisions.

State Department Views Submitted After Distribution of Camp David Papers

MINIMUM SAFEGUARD PRICE

The IEA Governing Board agreed on March 20 on a policy concept for an overall program of long-term cooperation. It provided that a major element in this overall program would be an agreement to encourage and safeguard new investment in conventional alternative energy sources by establishing a common minimum safeguard price below which IEA countries using tariffs, levies, etc., would not allow imported oil to be sold within their domestic economies. The U.S. played a major role in fashioning the IEA agreement. The U.S. had recognized the implications of the large differential between production costs of alternative sources in IEA nations and OPEC production costs as well as the possibility that other industrial countries could gain a competitive advantage in world markets by "free riding" on a major U.S. effort to reduce oil imports. To protect U.S. investors from the risk of predatory pricing by OPEC nations, the President asked for standby authority to use tariffs, quotas, or other means in the Energy Development Security Act of 1975, Title IX of the Energy Independence Act of 1975.

The March 20 decision (and the basic IEP Agreement itself) provided that the Governing Board must take decisions on the overall long-term program by July 1. A U.S.-chaired working group has now produced for the Governing Board an elaborated program based on the March 20 decision. Several issues remain open for Governing Board decision. Of these, the key issue for the U.S. (as well as the other countries) centers around the level of the MSP and precisely when it should be fixed.

KEY ISSUES

I Timing

The prospect of the July 1 IEA Governing Board action regarding the minimum safeguard price makes timing the most immediate policy question to be considered. We must decide whether during the meeting of the IEA Governing Board at the end of June we should seek agreement on a specific price level or construct a process in the overall agreement on long-term cooperation through which the specific level would be agreed by participating countries by a specified date.

Deferral of the selection of a specific level would postpone choices during a period of U.S. economic and energy policy uncertainty. Although under this negotiating stance, no specific protection price would be set at this time, the prospect of protection for investors in energy resources would be established and there would be a commitment to set a level for the MSP within a period of months. Politically, there has been negative Congressional reaction to the MSP concept, and arguing over a specific level or mechanism at this point may endanger cooperation on other issues.

A decision to defer until a later specified date would also permit individual countries to develop programs in response to domestic economic realities and priorities. In regard to the IEA as a whole, the resolution of technical issues in a measured and deliberate manner might ultimately produce stronger agreement among the IEA nations.

On the other hand, it can be fairly argued that failure to specify mechanisms and select a level immediately may weaken the IEA's position vis-a-vis the producer nations since no tangible evidence of consumer solidarity is provided. Also, the U.S. determination to develop alternative resources is not as strongly signaled to OPEC. A specific level articulated now would give investors a detailed idea of which investments will prove feasible in the long run. The acceptance of a minimum safeguard price might also provide OPEC nations with a long-term minimum price planning base, reduce uncertainty in the market, and thus help normalize producer-consumer relations. Further, given the high level of current world prices, agreement on the specifics might prove easier now than in a future in which prices may have declined. It should also be noted that since the U.S. has led the way on the minimum safeguard price concept, any reluctance to push ahead on specifics might raise doubts about U.S. credibility and seriousness of purpose in the IEA. These considerations illustrate that the selection of the level of the MSP cannot be delayed indefinitely without gravely jeopardizing chances of getting a politically and economically credible IEA agreement on alternative sources development.

II Price Level

FEA analysis has shown that a price in the vicinity of $7 (1973 dollars) would protect major sources of increased U.S. supply (Outer Continental Shelf and Alaska oil). Additionally, a price in this range would have a positive conservation effect, and would hold U.S. oil imports to about 5.6 MMB/D by 1985 (PIR forecast, assuming accelerated supply plus conservation programs). A much lower price would not serve the U.S. adequately in limiting demand or protecting major supplies (Prudhoe Bay, for example, comes on at $4.50/barrel; Lower 48 old field secondary recovery at $5.00). On the other hand, a price much higher than $7.00 would appear to legitimize cartel price hikes and put the consuming nations in a contradictory position in negotiations with producers, especially on claims that high OPEC prices were damaging the economy.

III Implementing Mechanism

The negotiating history of the MSP to date indicates that the Governing Board will probably agree on a formulation which leaves to each IEA country the choice of the mechanism it will employ to meet its commitment under the MSP. Countries may be required to select such measures from an agreed list likely to include variable levies, fixed tariffs, quotas and state trading monopolies. An agreed list would be drawn up on the recommendation of technical experts during the coming months. If the U.S. import fee sticks, we can legitimately take a position within the IEA that we already have a mechanism in place to maintain the MSP.

BACKGROUND

Reaction to the minimum safeguard price concept in Congress has been generally cool. The thrust of an OPEC price break in the near term has not garnered much public credibility, and there has been some feeling in Congress that the Administration does not currently have the authority to engage in IEA minimum safeguard price negotiations. At the same time, the argument exists that protection of domestic investment in alternative sources could be achieved through targeted deficiency payments. This method would shift the supply emphases from an IEA cooperative mode to a more narrowly defined domestic supply strategy with potentially enormous Treasury exposure, but deficiency payments have their proponents in the Congress.

Title IX of the Administration's Energy Independence Act is temporarily dormant. No hearings were scheduled by the committees to which the original bill was referred. Existing executive authority under Section 232 of the Trade Expansion Act of 1962 could be relied upon for negotiating authority. However, the Ullman bill would amend Section 232 to remove this flexibility, and S621 (passed by the Senate May 1, 1975) would effectively add a veto provision to the exercise of this authority for price floor purposes.

Within the Administration, the minimum safeguard price issue has not produced a unified stand. On the negative side one view is that while such a barrier might help insulate domestic producers, consumers would be insulated from certain beneficial effects of a downward price movement. Further, the wisdom of government entry into the international petroleum market is questioned given the general uncertainty of the market. The opposing view points to the positive effect of a correctly set price level on the development of alternative energy sources and in preventing a resurgence in oil demand when the price breaks. If the minimum safeguard price concept produces a strong IEA consensus, OPEC may be confronted with an effective counterforce to the producer cartel. Also, it is noted that implementation of the concept does not require direct intervention in the world petroleum markets unless and until we are successful in driving down world oil prices.

The IEA's Standing Group on Long Term Cooperation has this week reported to the Governing Board the results of its intensive examination of technical issues related to the MSP. Some of these remain unresolved, but they are not key decision variables. The Schedule for specifying the safeguard price level is the paramount issue for early resolution.

G

NUCLEAR POWER

The existing threat to the "nuclear option" of national energy development stems largely from the complex interaction of public perception, Federal statutes, and regulation by government at all levels. The necessity to make continued use of nuclear power is recognized by most agencies of the Federal Government. However, there is a wide divergence of views on the following questions:

-- To what extent must we depend on electrical power, and specifically nuclear energy, in the future?

-- How serious is the present threat to continued use of nuclear energy, and can coal provide the difference?

-- What Federal actions, if any, are required to counter this threat to continued use of nuclear energy?

KEY ISSUES

I. What Should be the Federal Government's Role in Ensuring that Sufficient Nuclear Power is Available to Meet the Energy Needs of the Nation?

Today, nuclear power provides roughly 8% of the total electricity supply. About 45% is from coal, 32% from gas and oil, and 15% from hydroelectric. Between now and 1985, an additional 270,000 megawatts of capacity is required if the growth in peak demand averages 5% per year after 1975. An additional 420,000 megawatts of capacity would be required if the growth in peak demand averages 7%/year. There is little disagreement within Federal executive agencies that coal and nuclear are both needed to supply the additional capacity. Neither can do it alone even at the lower growth rate.

Some proponents feel that the role of nuclear in 1980 or 1985 is beyond the ability of the Federal Government to influence directly, and the best that can be done is to assist State and local Government and utilities with strong guidance on which to base their energy facilities planning--recognizing the constraints that exist. Such planning would take account of the demand possibilities, the institutional licensing constraints, physical and environmental siting constraints, and availability of capital, all of which effect the decision of how much and what type of electrical generating capacity to build, and how early to retire existing oil and gas units. This approach to formulating energy policy is the objective of section 803 (National Energy Siting and Facility Report) or the Energy Facility Planning and Development Act of 1975 (Title VIII)).

The opposing view is that rather than focusing Federal programs on broad planning efforts at the State and local levels, the focus should be on actions to remove constraints; and that such actions can be successful in preventing power shortages in the 1980's and/or major increases in our consumption of petroleum products to make electricity. These actions, might involve expediting the siting, environmental hearings, and licensing process, so as to reduce the lead time for building new plants; closing the back end of the fuel cycle (reprocessing), promoting the real standardization of new plants, and in general providing a framework of stability of Government regulations and policies which industry can rely on in their decisions to proceed with plant construction. This view holds that the real problem is to remove the constraints, and not to develop a master plan which accepts the constraints as a matter of course.

II. <u>Are Current Reactor Safety Regulations Going Beyond that Which is Required to Adequately Protect Public Health and Safety?</u>

The question here is how safe is safe enough? Underlying this entire issue of reactor safety, is the consideration of the safety and extent of risk which is acceptable to the public from nuclear power without evaluating at the same time the equivalent risk that would be faced by the public if the power were being provided by some other source--coal, oil, etc. The Nuclear Regulatory Commission is by law restricted to the role of regulating the design and operation of nuclear plants so as to protect the public health and safety and the quality of the human environment. There is great latitude, however, in the interpretation as to just what degree of safety is sufficient.

It can be argued that some of these regulatory activities go beyond the question of safety and public health and actually deal with matters that should be left to the operating utilities. For example, should the design of steam turbines to assure satisfactory performance be subjected to review as a matter of reactor safety?

Another concern has been the practice of directing that design features be added to ameliorate the consequences of hypothetical accidents. New ones are being thought of each year that have an ever increasing remoteness of occurrence. It can be argued that this is an undue preoccupation with extremely remote occurrences and tends to divert Government and industry attention from those quality design and construction activities which are important to prevent the accident in the first place.

There are others who feel that the present approach to reactor safety is correct, and in fact should be further enhanced by more research into the consequences of hypothetical events such as pressure vessel rupture, of the loss of coolant accidents, etc.

To resolve this issue it must be determined if there is some way, in the long run, to balance regulatory decisions so that energy is provided at the least risk for society, with each decision considering all the energy sources and their respective risks.

III. What Can be Done by the Federal Government to Reverse the Current Trend of Increasing Delays in Siting and Licensing of Nuclear Power Plants?

Many of the existing regulatory constraints have been developed in order to protect the public interest, and the regulatory process may be proceeding as efficiently as practicable under the circumstances. These circumstances include very real public concern--well meaning activists who intervene in licensing cases and public hearings, some with legitimate issues--and court decisions which predominantly favor the intervenors and the path of continued delay.

Some proponents of nuclear power feel that, within the constraints of the existing law and giving due allowance to legitimate public intervention, there is still room for vast improvement in the preconstruction license process. They point to extended lengths of time required for local hearing boards to perform the public hearing process--and the length of time required to develop findings on issues including, in many cases, the review of whether the electric power is really needed when the utility says it is. Several examples have been cited recently which indicate that delays in construction license proceedings are now getting longer, rather than shorter as requested by President Ford last October.

Another element of the licensing problem relates to the backfitting of new requirements into a plant which is already approved for construction. When new facts are learned which could affect public safety, NRC has a responsibility to assess them and if warranted, require both operating plants and those under construction to backfit design features which recognize the new facts. Frequently, backfit is required only in those plants under construction, but not in operating plants. This has caused major increases in the cost of construction and extensive delays in completion (greater than $100 million and one year delay in some cases). Some view the practice as unnecessarily detrimental to the nuclear industry.

A factor contributing to licensing delays is the evaluation process relating to the demand for electricity, and whether conservation and reduced demand could serve as a viable alternative to constructing a new nuclear plant. NEPA requires that this be examined by the licensing agency during the environmental review process. Because of the NRC staff load, this has led to delays in some critically needed nuclear plants. In this period of rapidly changing energy use patterns, utilities and NRC are finding it increasingly difficult to keep their load projections on a current basis.

IV. Is the Federal Government Doing Enough to Encourage Standardization and Reliability of Power Plants?

The issue here is not whether the standardization of nuclear plants is desirable or that it will lead to substantially reduced construction cost and time--all agencies seem to agree that it is a good thing. The issue is one of implementation. One view is that by its actions, the Government is doing more to discourage standardization than it has done in words intended to encourage standardization. There have been some cases of industrial submittal of standardized designs to the NRC for approval; however, none have been approved. Also, some utilities report that their attempts to build identical plants to those already constructed, as advocated by NRC, are being partially thwarted by numerous NRC requests for design changes.

Another aspect of the standardization issue is the subject of the productivity in operating nuclear plants. Some of the key issues raised in a recent reliability report are: (1) whether or not State Regulatory Commissions should be encouraged to reflect in their rate base incentives for improved power plant productivity and; (2) what Federal actions should be taken and by whom to pull together some of the needed data on the causes of power plant outages?

V. What Actions Should the Federal Government Take to Depolarize the Nuclear Debate and Increase Public Understanding?

Because of the extremely effective campaign mounted by the anti-nuclear movement, most American citizens and their representatives are probably quite confused as to the safety of nuclear plants and their benefits. Until now, the Administration has contributed to this confusion with different agencies assuming various degrees of support or opposition to specific aspects of the nuclear program. The Federal Government might address the solution of these problems through more coordinated action within the Administration and by comparing the risk of nuclear power with the risk of other energy sources in a manner the public and Congress can understand and accept.

VI. What Approach Should be Taken Toward the Recycling of Plutonium and the Disposal of Nuclear Power Reactor Waste?

The viability of nuclear power as a significant energy resource depends on the ability to use plutonium. There are differing views as to when plutonium must be in use to prevent a fuel shortage and whether additional safeguarding measures must be in place before NRC approves plutonium recycle. The question is: what effect will the recently announced provisional decision by

NRC to delay the recycle decision until 1978 have on the ultimate availability of uranium, on the cost of electricity, and on the survivability of the nuclear industry?

NRC argues that its decision will avoid having a court reversal which could delay plutonium recycle even further. NRC's position reflects CEQ's argument that a decision on safeguards must be made before NRC proceeds to license plutonium recycle. Others argue that decisions on plutonium recycle could and should be taken within 12 months without corresponding safeguards. This was also the NRC/AEC staff position in their draft Generic Environmental Impact Statement on plutonium recycle.

Whether nuclear plants will have sufficient fuel storage space to prevent premature shutdowns is clouded by recent citizen intervention in utilities' applications to NRC to extend their storage space. Such interventions may cause major delays in enlarging storage capacity. On the other hand, delays may be short-lived. The cost of enlarged storage is relatively small compared to total power generating costs. It may be that if a plutonium recycle decision is made in 1978, an adequate reprocessing industry can still be developed. If plutonium recycling is not approved in 1978, arrangements might be made to bury the entire irradiated fuel assemblies without reprocessing. The technology for this may or may not be simpler than disposal of radioactive wastes from a reprocessing plant.

It is likely that the NRC decision will delay the two existing fuel reprocessing ventures by much more than three years and could cause these ventures to be scrapped. Thus, it could be 1981 or 1982 before industrial reprocessing is started.

There are two aspects to the waste disposal problem. Are the Federal efforts aimed at dealing with the problem sufficient? Is the problem itself viewed by the public in reasonable perspective, relative to other "waste disposal" problems faced by society? The Federal role for decisions on radioactive waste disposal is shared by ERDA and NRC; with ERDA having the responsibility of developing technology and providing an ultimate disposal site, and NRC having the responsibility to define, for commercial fuel reprocessors, what is an adequate level of integrity for a solid waste or other process.

One widely held view is that the program to develop processes and establish criteria for disposal is moving so slowly that much of the public criticism of nuclear power tends to have some validity--the Government really isn't moving forward with dispatch. Another view is that the program must continue to be built upon a solid foundation of R&D and what is needed is more R&D dollars. A third view, very common in industry, is that more R&D dollars are not the key to solving the problem and that existing technology is adequate to begin the task. A possible compromise approach is for ERDA and NRC to agree on interim criteria and "limited" storage plan at a Government facility that would at least permit the two present reprocessing ventures to demonstrate that radioactive wastes can in fact be concentrated, solidified, and stored in a manner which provides adequate protection for the public. Unless this demonstration is made, it may be that intervenors and courts will prevent NRC from approving plutonium recycle even after safeguards are resolved.

H

OUTER CONTINENTAL SHELF DEVELOPMENT

The Outer Continental Shelf may potentially yield a large portion of our future oil and gas supplies. The goal of exploration and development of these resources is to augment our declining domestic reserves and reduce our dependence on foreign energy sources. Many of the issues which surround OCS development focus on the concerns for the environment and on the respective roles to be assumed by the Federal Government and the States which are affected. The historical lag time from the leasing of these areas to production is generally 5 to 8 years, consequently any actions that hinder or delay this development must be critically examined and the benefits and consequences carefully measured. At issue is the need to balance rapid OCS development with valid social and environmental concerns.

KEY ISSUES

I. Revenue Sharing and Impact Assistance

Due to coastal State concerns over possible costs imposed on them by OCS development and possible delays in realizing OCS benefits which could result from State concerns and opposition, proposals have been made for sharing OCS revenues with affected States. Two basic approaches have been suggested: (1) an impact aid program consisting of project grants covering specific kinds of OCS-related onshore activities, and (2) unrestricted grants to States based on some specified formula -- e.g., related to OCS production landed, to population, or to some combination of factors as in General Revenue Sharing.

Previous Administrations have opposed the sharing of OCS revenues on a number of grounds: OCS revenues belong to all States; sharing Federal revenues would require higher Federal taxes, budget cuts elsewhere, or more debt; onshore development eventually increases State and local tax bases to pay for needed services and facilities, existing Federal programs are available to meet OCS impact needs, and distribution of OCS revenues was settled by the Submerged Lands Act of 1953 and associated Supreme Court rulings. However, there are pressures for reconsidering this position: States appear to have a strong desire for front-end money especially in frontier OCS areas; shared revenues might reduce the chance of costly delays in OCS development by encouraging

State cooperation; and Administration leadership on this issue would contribute to a positive stance on national energy policy, and perhaps avoid less desirable solutions imposed by the Congress.

II. Separation of Exploration and Development Decisions

Recent proposals have recommended the separation of exploration and development into two distinct phases. In its most extreme form, this concept calls for exploration to be conducted by the Federal Government, a change requiring new legislation and a substantial change in the role of the U.S. Geological Survey. A more reasonable approach possible under existing law would be to sell leases conveying exploration rights immediately and making conveyance of the right to develop contingent on submission and approval of a development plan. Several reasons have been given for separating exploration and development: (1) exploration is likely to be delayed under current procedures because of State and local concerns about the impacts of development, (2) present procedures do not provide the States an opportunity to review onshore development plans and adjust their own programs, (3) planning for onshore facilities and infrastructure cannot be properly completed until the location of oil and gas deposits is known, (4) affords better estimates of total reserves essential to sound Federal energy policy planning. Conversely, separation of exploration and development decisions will: (1) provide an additional formalized opportunity for opponents of OCS development to block production, (2) interject another element of uncertainty in the development process, (3) require the design of a mechanism which will provide a meaningful review of development plans without unduly delaying the production of oil and gas, (4) provide no assurance that any development plan would be approved by a State. Moreover it is likely that more than one State would be involved in any OCS activity.

III. Federal and State Roles in OCS Planning

The majority of the coastal States are concerned that the present OCS procedures are inadequate to address State concerns which include environmental protection and the planning for onshore socio-economic impacts. Also of concern to the coastal States is their interest in revenues and bonuses. The coastal States will pursue whatever avenues are available to them to have their concerns addressed. Such challenges could take the form of challenges to environmental impact statements or a refusal to grant a crude oil pipeline right-of-way across State waters or a right-of-way to sites for onshore facilities. Given present OCS procedures, this could lead to a de facto moratorium both at the exploration and the development stages while judicial or legal remedies are sought. Even new procedures provide no guarantee that lawsuits would not be filed. In fact, any new rules would probably have to be tested in the courts."

Certain steps have been taken to alleviate these concerns. Interior held a meeting on May 21, 1975 with State representatives to discuss ways to improve Federal-State interface in the leasing program. Agreement was reached to establish a National Advisory Board composed of senior representatives from all Federal agencies in OCS development and the Governors of the coastal States. This board would provide a forum for broad policy discussion, as well as supervise ad hoc committees established to explore specific regional and/or technical issues.

The proposal to emphasize a separate approval of development plans will also provide an opportunity for substantial State input into the key Federal decisions concerning the OCS. A development review process could be instituted which would encourage the States to coordinate their decisions for the granting of pipeline rights-of-way and onshore siting with the Federal Government's decision to approve OCS production.

IV. Alternative Mechanisms for Leasing Federal Lands

Most OCS leasing in the past has been carried out under a bonus bidding system. This system results in high initial capital requirements and high risks to OCS lease acquisition. It is sometimes alleged that high costs and risks prevent participation of smaller operators, and that high bonus costs divert money from exploration and development. The royalty bidding experiment last fall provided evidence that participation of small companies may indeed be restricted by bonus bidding. On the other hand, the argument that capital is diverted from exploration and development to bonuses is not supported by theoretical or empirical evidence to date.

Under current legislative authority, bonuses may be reduced by either increasing the level of fixed royalty payments or by a royalty bidding system. Either approach reduces bonuses by making an increasing proportion of lease payments contingent on actual production. This, however, can but need not have undesirable side effects. When contingent payments are increased there is a higher probability that lessees will not produce even though production revenues are anticipated to be in excess of costs. The transfer of royalty revenues to the Government in effect raises the costs of production and can preclude development on otherwise economic leases. Thus, depending on reserves and cost of development for particular leases or leasing areas, there is a limit to how much royalties can be raised and bonuses reduced without seriously interfering with development. However, a well considered sliding scale royalty program could alleviate most of these problems. Interior is continuing to study this problem in an effort to identify circumstances where bonuses can be reduced, and the extent to which they can be reduced, without unduly jeopardizing development.

BACKGROUND DISCUSSION

I. Revenue Sharing and Impact Assistance

In the Submerged Lands Act of 1953, Congress granted States jurisdiction over the seabed extending three miles from their shorelines, including ownership rights to minerals thereunder. This legislation, which culminated a lengthy political controversy, was immediately followed by the OCS Lands Act of 1953, which contrary to existing onshore precedent, provided that all revenues from OCS mineral leasing be deposited in the General Fund of the U.S. Treasury. Thus, the original decision was to share revenues on the basis of territory rather than dollars. Doubts about the equity of this sharing arrangement have been raised in light of current circumstances--technological advances which expand the distance offshore where drilling is feasible, and discovery of reserves in frontier areas which lie totally beyond the three mile limit.

Public domain lands within States may not be taxed by the States; therefore, the Mineral Leasing Act of 1920 provides for payments to the States of 37 1/2 percent of Federal lease revenues, thus protecting the State's tax base. Offshore Federal lands do not constitute a part of a State's tax base, and revenues from these lands should accrue to the Federal Government.

II. Environmental Protection and the Separation Issue

Many of those who are unfamiliar with OCS procedures express great concern about environmental protection. However, a number of extensive and adequate procedures are currently required to assure that the environment is protected. The steps in the decision-making process are as follows:

(1) An area is selected for nomination of tracts by industry;

(2) A number of tracts are designated for study from the nominations;

(3) Environmental information is gathered by the Federal Government;

(4) A draft environmental impact statement is prepared considering the effects of leasing and development on the environment;

(5) The statement is published and offered to the public for comment;

(6) A public hearing is held to receive comments from all who wish to testify. Written comments are reviewed regarding the contents of the statement, and;

(7) All information is considered in the preparation of a final environmental impact statement.

These steps are all preliminary to the Secretary's decision to lease OCS lands. The procedure is designed to assure the opportunity for all responsible public and private points of view to be expressed. Interested parties are encouraged to involve themselves at appropriate stages in the development of the environmental impact statement. A Final Secretarial Decision on OCS leasing is predicated on the assumption that National, State and local governments have been involved in the process from beginning to end.

IV. Alternative Mechanisms for Leasing Federal Lands

Over the past twenty years, the oil industry has paid approximately $18 billion in bonus bidding and royalty payments for leases in the Outer Continental Shelf (OCS). The industry has produced about 3.6 billion barrels of oil, and 24.2 trillion cubic feet of natural gas. To this date, the industry has not generated cash revenues equal to the total expenditures for OCS lease acquisition and development. Presumably, their discussed oil and gas reserves will ultimately allow some rate of return on invested capital.

I

NATURAL GAS CURTAILMENTS

The gas supply outlook for the short term is one of worsening shortages in light of a continued decline in domestic production and proved reserves. Supplementary supplies such as LNG imports, Canadian imports, synthetic natural gas from petroleum hydrocarbons, etc., cannot begin to offset shortages, except on a limited local basis. This reduced supply base to meet consumers' demand has manifested itself in natural gas curtailments and restrictions on the use and availability of gas supplies.

Natural gas curtailments have increased substantially in recent years, from a modest amount of one percent in 1970, to an expected 15 to 20 percent of projected demand in the 1975-1976 period. Curtailments have caused widespread disruption in economic activities and have forced consumers to turn to alternate fuels at substantially higher cost. Because of domestic shortages in alternate fuels, imports have been relied upon to offset much of the gas shortage.

With the introduction of Title III of the Energy Independence Act, the Administration has taken steps to bring supply and demand into balance. Through new gas price deregulation, the Act will stimulate an increase in supply in the long run and decrease demand in both the long and the short run. (See background)

At issue now, is the management of the shortage which remains.

KEY ISSUES

I. <u>Should Action be Taken to Achieve Consistency in Federal Government Shortage Management Policy?</u>

<u>FPC Natural Gas Curtailment Policies</u>

The Federal Power Commission is the only Government agency which at this time has an established policy on the consumption and use of natural gas. This policy, applicable to all interstate gas pipelines in curtailment, has an "end-use" priority system of gas allocation. Residential and commercial consumers are first priority, and large interruptible gas consumers, the lowest. The basic philosophy behind the FPC curtailment policy is that priorities in deliveries of gas must be determined by alternate fuel capability of the curtailed gas consumers.

FPC and FEA Interface

A comparison of the FPC and FEA programs of allocation reveals some significant differences. FEA is primarily concerned with assuring an adequate supply of fuels to maintain industrial activity and to avoid unemployment and other economic disruptions due to fuel shortages. For example, residential consumers were told to turn down their thermostats during the height of the fuel crisis in the winter of 1973-74. In contrast, the lowest priority users on the FPC's curtailment list are large industrial boiler fuel users. There are reasons for this difference, such as the ability of consumers to use alternate fuels, and physical differences in the fuels themselves requiring different methodology for delivery, etc. Nonetheless, difficulties arise in assuring that consumers needing energy in whatever form are treated equitably, and national objectives are met.

FPC and State Regulatory Commissions

FPC curtailment policies are not necessarily in harmony with those of State commissions, nor are they acceptable to them in light of vested interests and their own objectives and programs. Because FPC jurisdiction does not extend to gas distributors, direct control over the disposition and curtailment of natural gas deliveries by local distribution companies is exercised by the respective State regulatory commissions. This situation would suggest that a State commission could reallocate supplies within the State to meet demand for gas which may be in variance with the FPC end-use priority. In practice, this does not appear to be the case, as the distributor may have his gas supply denied or reduced in the future because the end-use of gas was not consistent with the FPC priority system of allocation. FPC policy requires that both direct and indirect customers be placed in the same category of priority. This situation makes it difficult for State commissions to reallocate supplies within a State.

II. Should the Role of Natural Gas as an Energy Source be Reevaluated?

The natural gas shortage and resulting gas curtailments raise some serious questions about the role of natural gas as an energy source in meeting the Nation's future energy needs.

Natural gas is used primarily as a fuel, serving over 45 million consumers. It supplies 31 percent of the Nation's energy and, more importantly, 46 percent of the Nation's industry needs. Natural gas is also used in small quantities as a feedstock for making fertilizer, petrochemicals, and other small but important uses.

A program for natural gas should embrace the concept that natural gas is a valuable but dwindling natural resource which possesses qualities whose use should be maximized and directed toward high priority consumers. Such utilization would prompt these considerations:

A. Assign lowest priority to uses where the Btu loss is the highest. The use of natural gas in the production of steam should be discouraged and such use discontinued voluntarily through some form of financial incentives or legislation. The electricity sector, for example, currently consumes 15 percent of the Nation's gas supply.

B. Consider priority use where fuel substitution would impose higher total social costs, given present technology (textiles, glass manufacturing, ceramics).

C. Recognize priority use where the final product has high social values, such as fertilizer and petrochemicals.

III. Should Action be Taken to Alleviate the Impact of Gas Curtailments on Gas Utility Systems?

One important consideration in assessing gas curtailments is the impact that reduced deliveries of gas will have on gas pipeline and gas distribution systems, as well as the consumers they serve. These curtailments not only have a deleterious effect on the availability of natural gas for interstate gas consumers and its cost of distribution, but also increase the unit cost of transporting natural gas by pipelines. The fixed nature of gas pipeline costs allows some economies of scale or declining unit costs during periods of increasing throughput. But the situation confronting the gas pipeline industry, which has $18.7 billion of net assets in 1973, is one of declining availability of natural gas. As sales by pipeline diminish, costs must be spread over lesser volumes, thereby increasing the unit cost of gas sold by pipelines.

The decline in supply creates excess pipeline capacity. Some of this excess capacity may be put to use if additional sources of gas, such as Alaskan gas, SNG from coal gasification, and large-scale LNG imports, come on stream in the future. The alternative, of course, is to convert some pipelines to the transportation of other petroleum hydrocarbons. The recent announcement by El Paso Natural Gas Company to convert a 700-mile section of pipe in New Mexico, Arizona, and Texas for the delivery of North Slope oil to refiners in the Southwest is an example of this kind of action. Policy decisions made with respect to natural gas and other energy sources will have decisive impact on the gas utility industry and its customers. Management decisions must be made well in advance to assure the economic well-being of the industry. These decisions are obviously influenced a great deal by governmental actions.

IV. Should Action be Taken to Encourage Conservation of Natural Gas?

In dealing with the natural gas shortage, efforts have been made to reduce consumption. The President, in his January 15, 1975, State of the Union Message, proposed an excise tax of 37 cents per thousand cubic feet of gas.

With the realization that for the short term there are limited options to deal with gas curtailment, reduction in gas consumption becomes an important consideration. Some options worth considering are:

A. Impose a surcharge, or prohibit excess uses of natural gas consumed on site in the industrial, residential, and commercial sectors.

B. Impose a conservation excise tax on natural gas usage.

C. Direct the use of oil, in lieu of natural gas, among large users in the industrial and utilities sectors.

GENERAL BACKGROUND

Wellhead Price Regulation

It is currently conceded by those having an interest in the gas problem that regulation of wellhead pricing is the primary cause for the critical gas shortage that prevails today. The most effective way to deal with the shortage and bring supply and demand into balance is to completely deregulate the wellhead price. Realizing the impact that complete deregulation action would have on the consumers, the administration and other interested groups have advocated deregulation for "new" gas only. This approach would encourage producers to explore for and develop new sources of gas supplies, but would reduce the impact on consumers because "old" gas would continue to be subject to continued regulation.

Deregulation for "new" gas is not expected to add significant new domestic supplies of gas in the short term because of the long lead time, three to five years, to bring new supplies on line; however, it will gear up the industry to accelerate exploration and development for natural gas, and perhaps reduce shortfalls or maintain them at current levels.

Deregulation for "new" gas has received wide support by all interested Government agencies and many private organizations as well.

In the Congress, however, various alternative proposals have been introduced to deal with the gas shortage. The most significant bill considered by Congress is the Hollings-Magnuson Bill (S. 692). On May 6, 1975, the Senate Commerce Committee reported S. 692 out of Committee. Floor action is expected in the last two weeks of June.

Perhaps the most far-reaching aspect of the bill is the extension of FPC jurisdiction to intrastate sales of "new" gas. Although old gas sold within the State in which it is produced would not be affected, all new gas, regardless of where it is used, would be under FPC control. The FPC would continue interstate price controls on old gas, and establish a national cost-based ceiling in the range of 40 cents to 75 cents per thousand cubic feet (Mcf) for all new natural gas. The national rate would have an automatic annual adjustment for inflation, and would be reviewed and reestablished every five years on a national and high cost area basis. Small independent producers with sales of less than 10 million Mcf annually would be permitted to charge up to 150 percent of the national rate for new gas, provided that the gas had not been discovered by a large producer.

The Hollings-Magnuson Bill also requires that all production of new natural gas from Federal lands, after January 1, 1975, must be sold to an interstate pipeline. A State with Federal lands on it will not have access to gas produced from those lands.

The bill, if enacted, would outlaw future joint venture arrangements on Federal lands between "major oil companies." This will result in a major restructuring of the oil and gas exploration and production effort.

The bill empowers the FPC to order interconnections, require deliveries, and allocate gas among pipelines in emergency situations. The bill also contains proposals for the priority uses of natural gas, allocation of old and new gas to end-users, and extension of FPC authority over SNG plants.

Background on Issue I (What action, if any, should be taken to achieve consistency in Federal Government shortage management policy?)

To alleviate hardships to individual consumers, the FPC complements its curtailment policy by providing for individual consumers to seek extraordinary relief. Assuring industry with an adequate supply of natural gas is not a paramount consideration in the FPC priority system. The gas shortage has had a serious impact on various industries which have historically relied on natural gas as a primary fuel, and have alternate fuel capability, but have made no efforts to seek alternate fuels or provided for adequate "on-site" storage to use alternate fuels. Regrettably, some industrial consumers never believed in a gas shortage until they were notified by their supplier of a cut-off in gas deliveries.

FEA has a program to assist curtailed gas consumers with locating alternate fuels. This has been reasonably effective because of an adequate supply of these fuels at this time. But if this comparatively balanced supply/demand situation is disrupted, FEA's responsibility is to assure adequate supplies to its priority customers under the Mandatory Petroleum Allocation Act of 1973, and curtailed gas consumers may not find alternate fuels readily available.

J

UTILITY FINANCING ALTERNATIVES

The central issue involving the investor-owned electric utility industry is the extent of the present financial difficulties of the industry and its ability to provide an adequate long-term supply of electric power.

During 1974, there was a broad consensus that the investor-owned electric utilities were in financial peril. Inflation, soaring fuel and interest costs, massive construction budgets, and regulatory lag seriously eroded utility earnings to the point where they were unable to compete effectively for external funds. Bankruptcy for some utilities seemed imminent. Since that time, the financial outlook for utilities has considerably brightened. Electricity rates have increased 63.1 percent from June 1973 to December 1974 for industrial and large commercial customers, and 37.5 percent for residential customers.

During the latter part of this period, inflation decelerated, fuel costs stabilized, and utilities made massive cuts in their construction programs. For example, utilities deferred or canceled over 188,500 megawatts of potential generating capacity during 1974. This represents the equivalent of 41 percent of our existing generating capacity. The result has been an improvement in utility earnings. During the first quarter of 1975, utilities posted a national average profit of 67 cents per share, the highest in two years. Many people are interpreting this as a wholesale return of the industry's long-term financial health. Yet to do so may overlook the fact that the above massive construction cutbacks have contributed greatly to the increased profits by virtue of significantly reduced construction costs and the attendant interest payments. As discussed in BACKGROUND, however, these construction cutbacks may jeopardize the ability of the utilities to insure an adequate long-term supply of electric power. Existing energy policy initiatives for this industry are discussed in Section III of BACKGROUND; however, it may be necessary to develop additional vehicles for more direct assistance to electric utilities.

KEY ISSUES

I. Federal Loan Guarantees

The Federal Government would guarantee utility debt for the construction of coal and nuclear-powered generating facilities. The availability of the loan guarantee would be dependent on the State utility regulatory authorities' approval of stipulated rate increases to allow a minimum rate of return required to enable the utility to sell debt and equity at competitive rates. One advantage of this approach is that it would allow a utility to issue debt in greater amounts than allowed without the Federal loan guarantee and would allow a minimal reduction in utility interest rates. Another advantage of this approach is that it would require no large capital outflow from the Federal Treasury to initiate construction. The disadvantages of this approach are that it would require a Federal bureaucracy to manage the program, it might lead to Federal take-over of utilities in the event of loan default, and represents Federal intervention in the free marketplace.

II. Utility Finance Corporation (UFC)

A UFC would be established to purchase a special class of utility preferred stock and thereby provide urgently required capital funds to financially troubled utilities. In order to be eligible for such assistance, both the utility and the state utility regulatory authority would have to agree to a series of actions aimed at improving the financial health of the utility, such as implementation of the Federal utility ratemaking guidelines. In essence, therefore, adoption of these provisions would negate the requirement for financial assistance from the UFC, other than possibly for short-term assistance.

The advantage of this approach is that it would provide a mechanism for Federal financial assistance of last resort if critically needed. The disadvantages of this approach are that a Federal bureaucracy would have to be established to administer the UFC, it would set a precedent for similar Federal financing corporations to provide financial assistance to other troubled industries such as airlines and construction, and does represent Federal intervention in the free marketplace. It also would require large capital outflows from the Federal Treasury and presents a serious disengagement problem should the Government change its policies and approach.

III. <u>Allow dividends on utility common stock and new issues of preferred stock to be tax free to recipients</u>

Implementation of this proposal would provide a stimulus to equity investment in utilities by raising the market value of outstanding issues. The tax free benefits would be limited to individual, noncorporate holders, as corporations already enjoy up to an 80 percent exclusion of dividends from income.

For an individual in a 28 percent (or lower) marginal tax bracket, the tax free receipt of dividends would be equal to a fully-taxed 40 percent (or greater) increase in dividends. The dividend to after tax earnings payout ratio of electric utilities is generally constant at about 67 percent. (1964 - 1974 range: 65 to 67 percent). Thus, a 40 percent increase in dividends would have the same effect on common stock prices as a 40 precent rise in earnings. Such a rise in earnings should bring market prices closer to the book value of the utilities affected.

For a taxpayer in a greater than 28 percent marginal tax bracket the effect would be more pronounced. Thus a taxpayer in a 35 percent marginal bracket would require a 54 percent rise in a fully taxed dividend (equivalent at a constant payout ratio to a 54 percent rise in the utility's after tax income), to equal his cash received from untaxed dividends. For him, the utility's stock would be valued at about 1.2 times the book value.

There are several shortcomings with this approach. Tax free dividends might not be helpful to those companies in the most critical positions, as investors seeking tax free dividends would probably purchase the stocks of those utilities not experiencing great financial difficulties. While this proposal will stimulate equity investment in utilities, a greater stimulus would occur if the tax exclusion applied only to new issues. Similarly, if the tax free stock election proposal were adopted the inducement for equity investment would be greater. If these proposals were adopted, the revenue loss to the Treasury in 1975 would be approximately $1.5 billion for the tax free common stock dividend provision; $1.0 billion (at a 70 percent participation) for the tax free preferred stock proposal. The effect of preferred stock being made tax free is small as most preferred stocks are held by corporations and are presently largely excludable from taxable income.

IV. Federal guaranteed purchases of power

Under this proposal, the Federal Government would enter into contracts with utility companies to purchase a definite proportion of the output of newly constructed non-petroleum fired generating plants. The Government would then resell the power to utility companies as substitute power for that which is normally generated using petroleum.

The objective of this program is to provide an incentive for utility companies to resume construction of nuclear and coal-fired plants by guaranteeing a market for the output. In addition, any surplus production from these plants could be substituted for oil-fired generation. This could promote a significant reduction in the use of oil-fired plants. Furthermore, the prospect of guaranteed future revenues would provide a sufficient inducement for renewed investor demand for utility debt and equity issues. This approach also has many serious shortcomings.

While the proposal would remove some of the uncertainty from utility long-range planning efforts, it would do little to rectify the current financial crisis. Many of the utilities that have cancelled plants currently have coverage ratios at or below their legal limits. Without immediate increases in pre-tax earnings, additional debt could not be raised. Furthermore, some of the companies in question are at or close to their debt to equity limits and would first have to issue additional equity securities. It is doubtful that the expectation of "reasonable" revenues from a facility to be constructed would be sufficient to inspire investors to bid up the price of common stock to book value and permit reasonable expansion of the equity base without excessive dilution of existing stockholders.

In addition, there appear to be some serious practical problems which must be resolved before this proposal could be implemented. Some of these problems are listed below:

A. How will the purchase price be determined, and on what basis will it be paid? If the Federal Government purchases the power based on projected costs, it may not be sufficient to cover the actual costs. If the price is variable as a function of facilities costs and expense, then the "cost plus" aspect is open ended and clearly not in the best interests of the consumers. Will payments be made even if the plant is shut down or is not used by the Government? Finally, these payments will be made well into the future, and would do little to alleviate current financing constraints being experienced by a utility.

B. On what basis would utilities purchase the Government power? Would the state regulatory commissions be forced to buy such power at the Government's cost plus a mark-up, and if so, does that violate their basic responsibility to protect the consumers in their state. There are methods of overcoming this problem if the production of the electricity were on a competitive basis. This program, however, does not take cost of generating electricity into account, but merely requires that a construction delay has occurred to qualify for financial assistance.

C. What criteria would be established to define a construction delay? Would three months be appropriate or a one-year delay minimum? Would a three-month delay be treated differently from a one-year construction delay in qualification for assistance?

V. <u>Federal Government-utility joint venture for construction of new non-petroleum fired generating plant</u>

Under this approach, the Federal Government would enter into joint ventures with private utility companies having a serious difficulty raising funds for construction of new non-petroleum fired generating plants. Assuming that the agreement would call for 50 percent participation, the Government obligation on the current $16 billion of construction postponements would amount to $8 billion. Since the utilities have already funded a major proportion of the total cost of construction, no delay would result from utility inability to raise their share.

Provisions in the agreement would require that the participating utility purchase the Government share in the project on an installment basis. Individual payments would begin the year following completion of the project. The amount of each payment could be determined on the basis of a fixed proportion of the total outstanding obligation, similar to a bond retirement sinking fund. An alternative approach would be a determination based on each kilowatt hour of power generated by the plant.

There would be some impact on the earnings picture of the participating utility. Since the portion of the plant "owned" by the Government may not be included in the rate base, the utility would not be entitled to any return. As the Government share is repurchased, it would be included in the rate base. This incremental addition to the rate base would result in a more uniform flow in the requirement for additional revenue thereby eliminating the one-time effect on utility customers which results from current practices of adding new plant to the rate base.

This program would expand Federal participation in electric power generating operations to a limited extent. Unlike TVA or BPA projects, the Government would not participate directly in the operation of the plant or in the distribution of the power. The Government role is limited to provision of construction funds and is not intended to be a permanent participating agreement. The venture would not be without a penalty since the repurchase of the Government share would include interest charges determined by a rate set above current long-term market rates in force at the time of the agreement.

VI. <u>Federal purchase-leaseback of generating plant</u>

This proposal would involve direct Federal Government purchase of nuclear and coal-fired generating plant. The utility company would exchange a fixed asset for cash, thereby improving the utility cash flow and liquidity situation. The company would enjoy the benefit of the direct access to generating capacity since they would retain operational control. Only title to the plant would change hands. With the funds accruing to the company from this transaction, initiation of new plant construction may be undertaken without relying on external capital for initial financing.

Since the plant is not owned by the company, it is probable that the state commission would remove it from the rate base, thereby reducing the base on which return on invested capital is determined. As a result, the revenues available for dividend distributions would be reduced, unless action were taken by the state commission to increase the allowed rate of return.

Although the plant would be removed initially from the rate base, a lease agreement of the lease-purchase type would eventually return the plant to the rate base. The company would be repurchasing ownership of the plant over the life of the lease. As a result, the plant would be returned to the rate base in increasing increments over the life of the lease agreement. This gradual phase would have much the same impact on the customer as the joint venture agreement.

The principal impediment to the implementation of this proposal is the provision in the typical bond indenture agreement which requires that bonds be secured by the property of the issuing company. If the Government is to purchase generating plant which represents bond security, the obligation to the bondholders must be discharged. New plant could be substituted for the purchased plant or the bond issue could be retired. Retirement of the issue could virtually eliminate the cash flow addition resulting from the sale depending on the age of the bond issue retired. Retirement or substitution would require approval of the bondholder which may be difficult to obtain.

BACKGROUND

I. Electricity Supply/Demand Projections

Historically the annual growth rate in average electricity demand has approximated 7 percent, with the exception of 1974 during which the load growth remained essentially flat.

This divergence from the historical trend was prompted by price-induced electricity conservation and a decelerating level of business activity. The crucial issue at this juncture is whether the load growth will remain relatively flat or will increase during the late 1970's and early 1980's to approximate the historical levels. There appears to be a growing consensus that the future load growth will increase to at least the 5 percent level, assuming that the economy recovers during this period. One could also make a strong case for a future load growth which exceeds the 7 percent historical growth rate by virtue of increased electrification. Requirements to decrease our dependence on imported petroleum products and to find substitutes for decreasing natural gas supplies require exploitation of our domestic coal and uranium reserves. Since electric power is the most acceptable use of these domestic energy sources, increased electrification seems inevitable. This shift to electric power has already begun in the residential heating market and additional shifts are projected in the industrial and commercial sectors of our economy.

Despite the massive construction cutbacks mentioned earlier, there is a consensus that utilities will be able to meet forecasted electricity demand during the next few years with existing capacity and near term capacity additions. The capacity which was deferred or cancelled during 1974, however, could severely affect the ability of the utilities to meet electricity demand in the late 1970's and early 1980's, especially if the load growth reaches the upper limits of the demand forecasts. The resultant power shortages would undermine the stability and viability of our economy, our standard of living, and our quality of life. As a minimum, these construction delays could necessitate a shift from the longer construction lead time nuclear and coal generating plants to oil and gas-fired turbines which have a 3-5 year building cycle if utilities find themselves short of capacity. For example, the announced cutbacks and deferrals represent 114,100 megawatts of nuclear capacity, or 61 percent of the total 1974 construction cutbacks. Since nuclear plants have an eight to ten year construction cycle, increased load growth in late 1970's and early 1980's cannot be accommodated with nuclear capacity. The result of this increased reliance on oil and gas turbines will be an increase in our imports of petroleum products which runs counter to our national energy objectives.

II. Utility Fuel Mix and National Energy Objectives

An assessment of the need for Federal assistance to electric utilities must include an analysis of the long-term supply and demand situation for electric power. It also involves an assessment of the risk/benefit of over-construction of generating capacity versus under-construction. Lastly, it involves an assessment of the ability of utilities to construct high front end cost nuclear and coal plants vis-a-vis oil and gas turbines in conformity with our National Energy Objectives.

The first two points have been covered in earlier sections of this paper. The third point involves careful consideration of the level of utility earnings required to attract external funds at reasonable terms to finance construction of these high front end cost generating plants. It also involves a probabilistic analysis of possible exogenous perturbations which could have an adverse impact on utility earnings and decrease their ability to support capital expansion programs. For example, regulatory lag could be lengthened due to increased customer resistance to higher rates. An increase in interest rates and/or a shortage of available debt funding, precipitated by the Government's deficit spending, could restrict utility earnings. An acceleration in the rate of inflation, construction and/or operating costs could erode utility earnings. Any of these factors could dramatically reduce the ability of utilities to expand generating capacity in a timely manner to meet increased demand for electric power. It should be noted that this timing is all-important due to the long construction cycle for nuclear and coal generating plants. An improved utility profitability situation in 1975-1976 will not enable utilities to bring new capacity on line by the late 1970's. The plant construction must begin today if this capacity is to be on-line by the early to mid-1980's. Yet is one quarter's brightened profitability situation sufficient to induce utilities to make multi-million commitments to construct new generating plants? The apparent answer is "no" as suggested by the fact that there have been no new orders for nuclear plant through April 1975. As utility construction programs continue to slide, the probability of inadequate electric power supply in the future continues to increase. This in turn also increases the probability that gas and oil turbines will have to be built as an expedient to meet this future demand. Is the Government willing to accept such risk?

III. Existing Energy Policy Initiatives

Alternative Federal assistance programs range from a limited intervention of the Federal Government in the electric utility industry and the utility regulatory system to wholesale intervention in the generation, transmission, and sale of electric power. Already considered and at the former end of that range are Title VII of the Energy Independence Act and Guidelines "Plus," subject of an ERC memorandum to the President.

A. Utilities Act of 1975, Title VII of the Energy Independence Act of 1975 (In Committee)

The intent of the Act is to increase utility cash flow and return on investment, thereby restoring investor confidence in utility debt and equity. This would be accomplished by establishing a series of minimum Federal standards for several key state regulatory practices as follows: Inclusion of CWIP in the rate base; The elimination of regulatory lag; Normalized accounting practices; An increase in the

ITC; and the introduction of a special class of preferred stock whose dividends are tax deductible by the issuer. In general, most utility industry representatives and financial analysts support the intent of the Act. They feel that if the provisions of the Act were implemented in a timely manner, the majority of the utility financing problems would be solved since they would result in an average increase in electricity revenues of approximately 13 percent. There are, however, serious reservations with this approach. Implementation of the provisions of the Act requires lengthy Congressional approval; State regulatory commissions could easily circumvent the intent of the Act; the legality of the Act could be challenged in the courts; and it represents Federal intervention in the free marketplace.

B. Guidelines "Plus"

This approach involves the issuance of national guidelines for electric utility ratemaking. The guidelines would cover such provisions as inclusion of construction-work-in-progress (CWIP) in the rate base, normalization of earnings, accelerated rate-making procedures, automatic rate adjustments, and use of a forward test period for evaluating rate changes.

Many of these provisions are incorporated in various State utility regulatory policies and procedures, but have not been uniformly adopted. In addition, the guidelines would not be mandated changes in State regulatory policies and procedures subject to challenge in the courts. The necessary support for adoption of the guidelines would be an energetic sales campaign among State regulators, consumers, and utility companies, as well as possible Federal incentives which would be provided upon adoption of the guidelines. Such proposed incentives include a permanent extension of the 10 percent investment tax credit for coal and nuclear power plants, cash payment for the unused Investment Tax Credit (ITC) in the years these credits are earned, and the deferral of accrued income taxes that result from putting CWIP in the rate base. Regardless of these incentives, however, it must be stressed that the guidelines must be aggressively promoted through testimony presented at the utility rate hearings and direct Federal Government coordination with all parties concerned with adoption of the guidelines.

The obvious advantage of this apprach is that no delays would result from legislative debate since no Congressional action would be required. Secondly, since the guidelines entail no mandated change in utility regulatory policies and procedures, they cannot be challenged by lengthy court debate. The disadvantage of this approach is that the successful adoption of the guidelines is predicated on the success of the promotion campaign and on the potency of the incentives to stimulate their adoption.